SUNCOR ENERGY INC.

ANNUAL INFORMATION FORM

Dated February 25, 2016

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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.

References to the 2015 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, 2015. References to our MD&A mean Suncor's Management's Discussion and Analysis, dated February 25, 2016.

This AIF contains forward-looking statements based on Suncor's current plans, 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 and Non-GAAP Financial Measures section of this AIF for information regarding risk factors and material assumptions underlying our forward-looking statements.

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

Crude oil is a mixture consisting mainly 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** is a naturally occurring solid or semi-solid hydrocarbon, consisting mainly of heavier hydrocarbons that are too heavy or thick to flow or be pumped without being diluted or heated, and that is not primarily recoverable at economic rates through a well without the implementation of enhanced recovery methods. After it is extracted, bitumen may be upgraded into crude oil and other petroleum products.
>
> **Light Crude Oil** is crude oil with a relative density greater than 31.1 degrees API gravity.
>
> **Medium Crude Oil** is crude oil with a relative density greater than 22.3 degrees API gravity and less than or equal to 31.1 degrees API gravity.
>
> **Heavy Crude Oil** is crude oil with a relative density greater than 10 degrees API gravity and less than or equal to 22.3 degrees API gravity.
>
> **Oil sands** are naturally occurring stratified deposits of unconsolidated sand/sandstone and other sedimentary rocks saturated with varying amounts of water and bitumen.
>
> **Synthetic crude oil (SCO)** is a mixture of liquid hydrocarbons derived by upgrading bitumen, or derived from gas to liquid conversion and may contain sulphur or other compounds. 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 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**.

Natural gas is a naturally occurring mixture of hydrocarbon gases and other gases.

Conventional natural gas is natural gas that has been generated elsewhere and has migrated as a result of hydrodynamic forces and is trapped in discrete accumulations by seals that may be formed by localized structural, depositional or erosional geological features.

Natural gas liquids (NGLs) are hydrocarbon components that can be recovered from natural gas as a liquid, including, but not limited to, ethane, propane, butanes, pentanes, and condensates. **Liquefied petroleum gas (LPG)** consists predominantly of propane and/or butane and, in Canada, frequently includes ethane.

Oil and gas exploration and development terms

Development costs are costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing 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, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells.

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

Reservoir is a subsurface rock unit that contains an accumulation of petroleum.

Wells:

> **Delineation wells** are drilled for the purpose of assessing the stratigraphy, structure and bitumen saturation of an oil sands lease. The wells are also used to define known accumulations for the assignment of reserves.
>
> **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.
>
> **Disposal wells** are drilled in areas where waste fluids can be injected for safe disposal. These wells are subject to regulatory requirement to avoid the contamination of freshwater aquifers.
>
> **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 of discovering 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 hydrocarbons 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 and 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 terms

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.

Extraction refers to the process of separating bitumen from oil sands.

In situ refers to methods of extracting bitumen from deep deposits of oil sands by means other than surface mining.

Midstream refers to transportation, storage and wholesale marketing of crude or refined petroleum products.

Overburden is the material overlying oil sands that must be removed before mining. Overburden is removed on an ongoing basis to continually expose the 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 of the resource and operation of associated facilities. 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-to-oil ratio (SOR) is a metric used to quantify the efficiency of an in situ oil recovery process, which measures the cubic metres of water (converted to steam) required to produce one cubic metre of oil. A lower ratio indicates more efficient use of steam.

Tailings Reduction Operations (TRO™) is a process involving the conversion of 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.

Upgrading is the two-stage process by which bitumen 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 periodically 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 crude oil, bitumen or natural gas.

Reserves

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	thousands of barrels
mbbls/d	thousands of barrels per day
mmbbls	millions of barrels
mmbbls/d	millions of barrels per day
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
mboe	thousands of barrels of oil equivalent
mboe/d	thousands of barrels of oil equivalent per day
mmboe	millions of barrels of oil equivalent
mmboe/d	millions of barrels of oil equivalent per day
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
bcfe	billions of cubic feet of natural gas equivalent
GJ	gigajoules
mmbtu	millions of British thermal units
API	American Petroleum Institute
CO_{2e}	carbon dioxide equivalent
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, mboe/d or mmboe on the basis of six mcf to one boe. Any figure presented in boe, boe/d, mboe, mboe/d, or mmboe may be misleading, particularly if used in isolation. A conversion ratio of six mcf of natural gas to one bbl of crude oil or NGLs is based on an energy equivalency conversion method primarily applicable at the burner tip and does not necessarily represent value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

Conversion Table(1)(2)

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

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

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

(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* (the CBCA) 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, the company further amalgamated with a wholly owned subsidiary under the CBCA. We amended our articles in 1995 to move our registered office from Toronto, Ontario, to Calgary, Alberta, and again in April 1997 to adopt the name, "Suncor Energy Inc."

In April 1997, May 2000, May 2002, and May 2008, the company amended its articles to divide its issued and outstanding shares on a two-for-one basis.

Pursuant to an arrangement under the CBCA, which was completed effective August 1, 2009, Suncor amalgamated with Petro-Canada to form a single corporation continuing under the name "Suncor Energy Inc."

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, 2015, 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 Products Inc.	Canada	A subsidiary 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 and power 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.) Marketing Inc.	U.S.	A subsidiary that procures and markets third-party crude oil, in addition to procuring crude oil feedstock for the company's refining operations. Through this subsidiary, we also administer Suncor's U.S. energy trading activities.
Suncor Energy (U.S.A.) Inc.	U.S.	A subsidiary through which our U.S. refining and marketing operations are conducted.
International operations		
Suncor Energy UK Limited	U.K.	A subsidiary through which the majority of our operations in the U.K. are conducted.

The company's remaining subsidiaries each accounted for (i) less than 10% of the company's consolidated assets as at December 31, 2015, and (ii) less than 10% of the company's consolidated operating revenues for the fiscal year ended December 31, 2015. In aggregate, the remaining subsidiaries as at December 31, 2015, accounted for less than 20% of each of (i) and (ii) described above. As at the date hereof, Suncor owns 84.2% of the issued and outstanding shares of Canadian Oil Sands Limited (COS), a company that is organized under the laws of Alberta.

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, power and byproducts.

Suncor has classified its operations into the following segments:

OIL SANDS

Suncor's Oil Sands segment, with assets located in the Athabasca oil sands 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 region. 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, cogeneration units, energy and reclamation facilities, such as Suncor's TRO™ assets.
  - **In Situ** operations include oil sands bitumen production from Firebag and MacKay River and supporting infrastructure, such as central processing facilities, cogeneration units and hot bitumen infrastructure, including insulated pipelines, 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.
- **Oil Sands ventures** operations include Suncor's 50.8% interest in the Fort Hills mining project, where Suncor is the operator, and its 36.75% interest in the Joslyn North mining prospect. The company also holds a 12.0% working interest in the Syncrude oil sands mining and upgrading joint arrangement and currently holds an additional 30.9% indirectly through its 84.2% ownership of COS, which owns a 36.74% interest in the Syncrude joint arrangement.

EXPLORATION AND PRODUCTION

Suncor's Exploration and Production (E&P) segment consists of offshore operations off the east coast of Canada and in the North Sea, and onshore assets in North America, Libya and Syria.

- **E&P Canada** operations include Suncor's 37.675% working interest in Terra Nova, which Suncor operates. Suncor also holds a 20.0% interest in the Hibernia base project and a 19.13% interest in the Hibernia Southern Extension Unit (HSEU), which was reset from 19.51%, effective December 1, 2015. Suncor also holds a 27.5% interest in the White Rose base project and a 26.125% interest in the White Rose Extensions. Effective January 1, 2016, a reset of Suncor's working interest in the Hebron project resulted in a decrease from 22.73% to 21.03%. Other than Terra Nova, all of the projects are operated by other companies. Suncor also holds interests in several exploration licences offshore Newfoundland and Labrador and Nova Scotia. E&P Canada also includes Suncor's working interests in unconventional natural gas properties in northeast B.C.
- **E&P International** operations include Suncor's 29.89% working interest in Buzzard and its 26.69% working interest in Golden Eagle Area Development (GEAD). Both operations are located in the U.K. sector of the North Sea and are operated by another company. Suncor also holds interests in several exploration licences offshore the U.K. and Norway. Suncor owns, pursuant to EPSAs, working interests in the exploration and development of oilfields in the Sirte Basin in Libya. Production in Libya remained substantially shut in at the end of 2015 due to political unrest, with the timing of a return to normal operations remaining uncertain. Suncor also owns, pursuant to a PSC, an interest in the Ebla gas development in Syria. Suncor's operations in Syria were suspended indefinitely in 2011, due to political unrest in the country.

REFINING AND MARKETING

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

- **Refining and Supply** operations refine crude oil and intermediate feedstock into a broad range of petroleum and petrochemical products. Refining and Supply consists of:
  - **Eastern North America** operations include a refinery located in Montreal, Quebec, a refinery located in Sarnia, Ontario, and a lubricants business located in Mississauga, Ontario that manufactures and blends products which are marketed 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, a sulphur recovery facility, pipelines and product terminals in Canada and the U.S.
- **Marketing** operations sell refined petroleum products to retail, commercial and industrial customers through a combination of company-owned, Petro-Canada™ and Sunoco™ branded-dealers in Canada and other retail stations in Colorado, a nationwide commercial road transport network in Canada, and a bulk sales channel in Canada. Lubricant products are marketed worldwide through company-operated locations and distributor networks.

CORPORATE, ENERGY TRADING AND GROUP ELIMINATIONS

The grouping **Corporate, Energy Trading and Group 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 wind facilities across Canada, including Cedar Point, which commenced operations in 2015, and the St. Clair ethanol plant in Ontario.
- **Energy Trading** activities primarily involve the marketing, supply and trading of crude oil, natural gas, power 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 insurance for a portion of the company's operations by the **Corporate** captive insurance entity.

Three-Year History

Over the last three years, several events have influenced the general development of Suncor's business.

2013

- **Voyageur oil sands upgrader project deferred.** Suncor determined not to proceed with the Voyageur upgrader project in response to changed market conditions that challenged the project economics. Concurrently, Suncor acquired Total E&P Canada Ltd.'s (Total E&P) interest in Voyageur Upgrader Limited Partnership (VULP) for $515 million to gain full control of VULP's assets, including a hot bitumen blending facility and tankage used to support the company's growing Oil Sands operations.
- **Majority of natural gas business in Western Canada sold.** Suncor sold its conventional natural gas business in Western Canada for gross proceeds of $1 billion, before closing adjustments and other closing costs. The sale included properties 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.** The company reached a reclamation milestone 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.** Ramp-up of Firebag Stage 4 was completed and 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.** Suncor and project co-owners unanimously agreed 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 ramp up to 90% of its planned production capacity of 180 mbbls/d (gross) 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 which resulted in production being shut in during this period.
- **Rail offloading facility complete.** Construction of a rail offloading facility to enable receipt of inland crudes at the Montreal refinery was completed. The Montreal refinery received its first shipment in early December.
- **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 in 2016.

2014

- **Market access initiatives.** Crude by rail shipments to the company's Montreal refinery averaged approximately 33 mbbls/d in 2014. In addition, the rail offloading facilities at Tracy, Quebec were used to move crude to new and existing markets. Suncor also started transporting heavy crude on TransCanada's Gulf Coast Pipeline, which provided increased access to global-based pricing.
- **Exploration interests in E&P Canada.** In May 2014, Suncor signed a farm-in agreement with Shell Canada to acquire a 20% interest in a deepwater exploration opportunity in the Shelburne Basin, offshore Nova Scotia. In December 2014, Suncor acquired a 30% interest in an exploration licence in the Flemish Pass off the coast of Newfoundland and Labrador and a 50% interest in another exploration licence in the Carson Basin near the Flemish Pass.
- **Joslyn North mining project scaled back.** In May 2014, Suncor decided, along with the other co-owners, to reduce spending on the Joslyn North mining project and continue engineering work and optimization studies to support the development plan for the project.
- **Investment in water management strategy.** Suncor commissioned a wastewater treatment plant, which is expected to increase the reuse and recycling of waste water from Suncor's upgrading operations and reduce freshwater withdrawal. In addition, Suncor, along with its project partners, approved the development of the Water Technology Development Centre (WTDC), which is expected to connect to Suncor's Firebag operations and provide an environment to test water treatment

and recycling technologies. The WTDC is scheduled to become operational in early 2017.

- **Reinforced Suncor's focus on core assets.** Consistent with Suncor's strategy to focus on core assets, Suncor sold its Wilson Creek assets in E&P Canada, announced the sale of its interest in Pioneer Energy's retail business, and acquired a sulphur recovery facility adjacent to the Montreal refinery.
- **MacKay River debottleneck and process optimization.** Suncor achieved first oil from the MacKay River facility debottleneck project in the third quarter of 2014.
- **First oil from Golden Eagle Area Development (GEAD).** First oil was achieved at the Golden Eagle project late in 2014, which ramped up to its peak production rate of approximately 18,000 boe/d (net) during 2015.
- **Libya operations shut in.** Production in Libya temporarily resumed in the latter half of 2014. However, political unrest in December of 2014 resulted in the Libya National Oil Company (NOC) declaring force majeure on oil exports from two terminals, resulting in the shut in of substantially all of the company's production by the end of the fourth quarter. Consequently, Suncor also declared force majeure for all exploration commitments in Libya effective December 14, 2014.
- **Firebag production exceeds nameplate capacity.** Firebag production in 2014 averaged approximately 95% of nameplate capacity of 180 mbbls/d, and greater than 180 mbbls/d in the fourth quarter. Continued infill and new SAGD well pair development allowed Suncor to optimize steam placement into the reservoir.

2015

- **Demonstrated commitment to Suncor's core business through further investment in the oil sands.** The company acquired an additional 10% of the Fort Hills mining project from Total E&P and now owns 50.8% of the project.
- **Upgrader utilization exceeds 90%.** Suncor's long-term commitment to operational excellence continues to drive operational efficiencies, including increased upgrader reliability.
- **Fort Hills construction ramps up with substantial completion of detailed engineering work.** Construction continues to ramp up with more than 50% of construction complete at the end of 2015. First oil is expected as early as the fourth quarter of 2017.
- **Firebag nameplate capacity increased from 180,000 bbls/d to 203,000 bbls/d.** Cost-effective debottlenecking activities have been completed at Firebag, with sustained production levels in excess of 180,000 bbls/d in 2015. This resulted in a nameplate capacity increase effective January 1, 2016.
- **Suncor offers to acquire Canadian Oil Sands Limited (COS).** In October 2015, Suncor made an offer to acquire all of the outstanding shares of COS. In February 2016, Suncor acquired 84.2% of COS and intends to acquire the remaining shares in 2016. The acquisition of COS will provide Suncor with an incremental 128,500 bbls/d of SCO production capacity and the potential to integrate the Syncrude assets with Suncor's Oil Sands assets.
- **Completion of asset exchange and lease with TransAlta Corporation (TransAlta).** Suncor assumed operating control of the Poplar Creek cogeneration facilities, which provide steam and power to the company's Oil Sands operations, in exchange for Suncor's Kent Breeze and its share of Wintering Hills wind power facilities. Bringing the Poplar Creek assets in-house is expected to improve Suncor's overall Oil Sands operation's reliability and profitability.
- **Enbridge's Line 9 reversal was commissioned during the fourth quarter of 2015.** The reversal provides Suncor the flexibility to supply its Montreal refinery with a full slate of inland-priced crude, enhancing the long-term competitiveness of the refinery.
- **Government of Alberta announced a new climate plan.** The new plan announced in late 2015 includes a carbon pricing regime coupled with an overall emissions limit for the oil sands. The climate plan places some certainty on the future greenhouse gas (GHG) costs for Suncor, while the limit on oil sands emissions sets the ambition for changing the trajectory of oil sands emissions.
- **Government of Alberta Royalty Review.** The Government of Alberta conducted a review of the province's oil and gas royalties. Subsequent to year end, the new royalty system was announced, which maintains the current oil sands rates, providing certainty and predictability for the industry.

NARRATIVE DESCRIPTION OF SUNCOR'S BUSINESSES

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

Oil Sands

Oil Sands Operations – Assets and Operations

Oil Sands Base Operations

Our integrated Oil Sands Base operations, located in the Athabasca oil sands 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 sand placement areas.

- **Upgrading**

  After the diluted bitumen is transferred to upgrading facilities, the naphtha is removed and recycled to be used again as diluent in the extraction processes. Bitumen is upgraded through a coking and distillation process. The upgraded product, referred to as sour SCO, is either sold to market 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.

- **Power and Steam Generation and Process Water Use**

  To generate steam for the mining and extraction process, the company uses either a cogeneration unit or coke-fired boilers. Electricity is generated by turbine generators, most of which are part of the Oil Sands Base cogeneration unit, or provided by cogeneration units at Firebag. Process water is used in extraction processes and then recycled.

- **Maintenance**

  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 may be 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. The company plans to complete a turnaround at Upgrader 2 commencing at the end of the first quarter of 2016.

- **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 manages tailings through a process known as TRO™. TRO™ has accelerated the company's tailings management processes, and is expected to be a key component of Suncor's tailings strategy. Suncor is developing new tailings processing technologies to augment the TRO™ process.

Oil Sands Base Assets

<u>Millennium and North Steepbank</u>

Suncor pioneered the commercial development of the Athabasca oil sands beginning in 1962, achieving first production in 1967. Bitumen is currently mined from the Millennium area, which began production in 2001, and the North Steepbank area, which began production in 2011. During 2015, the company mined approximately 168 million tonnes of bitumen ore (2014 – 149 million tonnes) and processed an average of 307 mbbls/d of mined bitumen in its extraction facilities (2014 – 274 mbbls/d).

<u>Upgrading facilities</u>

Suncor's upgrading facilities consist of two upgraders – Upgrader 1, which has an upgrading capacity of approximately 110 mbbls/d of SCO, and Upgrader 2, which has an upgrading capacity of approximately 240 mbbls/d of SCO net of internal consumption. 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 2015, Suncor averaged 320 mbbls/d of upgraded (SCO and diesel) production net of the company's internal consumption, (2014 – 289 mbbls/d) sourced from bitumen provided by both Oil Sands Base and In Situ operations.

Power and Steam Generation

In the third quarter of 2015, Suncor completed an exchange of assets with TransAlta. Suncor exchanged its 100% owned Kent Breeze and its 51% share of the Wintering Hills wind power facilities for TransAlta's Poplar Creek cogeneration facilities, which provide steam and power for Suncor's Oil Sands Base operations. The acquisition of the Poplar Creek cogeneration facilities is expected to enhance the reliability and efficiency of Suncor's Oil Sands operations. As part of the agreement, Suncor entered into a 15-year lease with TransAlta. The leased assets consist of two gas turbine generators and heat recovery steam generators. Ownership of these assets will automatically transfer to Suncor at the end of the term for a nominal amount.

Other Mining Leases

Suncor owns several other oil sands leases, including 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.

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**

  SAGD is an enhanced oil recovery technology for producing bitumen. It 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. Low pressure steam is injected into the upper wellbore 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 lower wellbore 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 through an insulated pipeline as hot bitumen.

- **Power and Steam Generation**

  To generate steam for operations, the company uses Once Through Steam Generators (OTSGs) or cogeneration units. OTSGs are powered by both purchased natural gas and produced natural gas 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 Alberta power grid.

- **Maintenance and Bitumen 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 experience natural production declines after several years. In an effort to maintain bitumen supply, Suncor drills new wells from existing well pads or 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 a total nameplate capacity of 203 mbbls/d. The nameplate capacity was increased from 180 mbbls/d to 203 mbbls/d, effective January 1, 2016, as a result of completing debottleneck activities. 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, 2015, Firebag had 12 well pads in operation, with 151 SAGD well pairs and 37 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 approximately 475 MW of electricity. The Firebag site power load requirements are approximately 110 MW, and Suncor exports approximately 365 MW of electricity to the

Alberta power grid. There are also 13 OTSGs at the site for additional steam generation.

During 2015, Firebag production averaged 187 mbbls/d (2014 – 172 mbbls/d) with a SOR of 2.6 (2014 – 2.8).

MacKay River

Production from Suncor's MacKay River operations commenced in 2002. As at December 31, 2015, MacKay River included six well pads with 98 well pairs either producing or on initial steam injection. The MacKay River central processing facilities have bitumen processing capacity of 38 mbbls/d. A third party owns the on-site cogeneration unit, which Suncor operates under a commercial agreement that is used to generate steam and electricity. There are also four OTSGs at the site for additional steam generation.

During 2015, Mackay River production averaged 31 mbbls/d (2014 – 27 mbbls/d) with a SOR of 2.9 (2014 – 2.9).

Suncor has regulatory approval to increase bitumen processing capacity by approximately 20,000 mbbls/d with an additional central processing facility at MacKay River (the MacKay River Expansion). However, in January 2015, Suncor deferred the timing of a sanction decision for the MacKay River Expansion as a result of the lower crude oil price environment.

Other In Situ Leases

Suncor owns and operates several other oil sands leases which may support future in situ production, such as Meadow Creek, Lewis, OSLO, and Chard and a non-operated interest in Kirby, on which it may undertake exploratory or delineation drilling. In 2015, Suncor drilled 98 stratigraphic test wells at Lewis, 13 gross wells at OSLO adjacent to Lewis and 53 gross wells at Meadow Creek; Suncor also participated in a net five wells at Kirby (10% working interest). Plans for winter 2016 drilling include an additional 54 stratigraphic test wells at Lewis, five gross wells at OSLO and 44 gross wells at Meadow Creek. Suncor holds a 100% working interest in Lewis, a 75% working interest in Meadow Creek, a 77.78% working interest in OSLO and interests varying from 25% to 50% in Chard.

Starting with Meadow Creek, Suncor is evaluating a greenfield growth plan with a concept to further develop new in situ reservoirs using a replication strategy to build standardized surface facilities, well pads and infrastructure. This plan is expected to reduce facility capital expenditures. The winter exploratory drilling programs are designed to identify sufficient resources to fill facilities associated with the replication strategy. A development application for Meadow Creek was submitted to the Alberta Energy Regulator (AER) in October 2015.

Oil Sands Ventures

Syncrude

Suncor holds a 12% interest in the Syncrude joint arrangement, and currently holds an additional 30.9% indirectly through its 84.2% ownership of COS, which owns a 36.74% interest in the joint arrangement. Syncrude is located near Fort McMurray and 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. Regulatory applications for these areas were submitted in December 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 natural gas and off-gas from upgrading operations. At Aurora North, Syncrude operates two 80-MW gas turbine power plants to provide electricity.

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 centrifuge technology that separates water from tailings.

In 2015, Suncor's share of Syncrude production averaged 30 mbbls/d (2014 – 31 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 (gross) of bitumen production capacity (91 mbbls/d net to Suncor). Fort Hills will use a paraffinic froth treatment process to produce a marketable bitumen product. Suncor originally acquired a 60% working interest in Fort Hills through the merger with Petro-Canada, and subsequently disposed of 19.2% as part of transactions with Total E&P. In November 2015, Suncor purchased an additional 10% working interest in the Fort Hills project from Total E&P.

Suncor now holds a 50.8% working interest in the Fort Hills project and is the operator for the project. The company's share of the post-sanction project costs is estimated to be $6.5 billion, including approximately $1.0 billion in acquisition costs. Approximately $2.3 billion of the company's 2016 capital budget has been allocated to this project. Project activities in 2016 are expected to focus on completing procurement for all areas, except mining, and completing construction in the ore processing plant, extraction and infrastructure areas. As at December 31, 2015, Suncor had incurred $3.5 billion post-sanction project costs with approximately 96% of the detailed engineering activities complete and 51% of the construction activities complete. First oil is expected as early as the fourth quarter of 2017.

Other Assets

Joslyn is an oil sands mining area comprising leases southwest of Fort Hills and on the west side of the Athabasca River that is operated by Total E&P. Preliminary designs for the Joslyn North mining project plan for 160 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. Although regulatory permits for the Joslyn North mining project have been obtained, in May 2014, Suncor, together with the other co-owners, agreed to scale back certain development activities. As a result of the decline in crude oil prices, in December 2015, the company wrote down the remaining carrying value of its share of the Joslyn mining project.

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. Development of new technology can take extended periods of time, first to demonstrate technical viability and then to demonstrate economic viability. The necessary validation typically occurs through a series of progressive tests which allow results to be reliably scaled and assessed for implementation.

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

- Oxy-Fuel Combustion – The OTSG Oxy-fuel Demonstration Carbon Capture Technology is a means to develop a reliable, lower-cost solution to capture CO_2 from once-through steam generators that can be used on a commercial scale for in situ bitumen production. By replacing air with oxygen in the fuel mix on SAGD boilers, the CO_2 produced will be more concentrated making it easier to capture, while at the same time greatly reducing oxides of nitrogen (NO_x) emissions.
- Zero Liquid Discharge – Suncor uses a zero liquid discharge process at our MacKay River in situ facility to achieve maximum water reuse by recovering waste water from produced bitumen.
- Enhanced Solvent Extraction Incorporating Electromagnetic Heating (ESEIEH) – This new method of in situ bitumen recovery uses radio frequency heating and solvents to reduce energy, GHG and water footprints. The second phase of the pilot project began operations in the third quarter of 2015, and is expected to continue for 18-24 months.
- N-SOLV™ – Suncor is currently undertaking field tests using this new method of in situ bitumen recovery, which uses a waterless, warm vapourized solvent technology to reduce energy, GHG and water impacts. The pilot test is ongoing and Suncor is currently in the planning phases for the next phase of piloting to demonstrate commercial feasibility.
- Steam Assisted Gravity Drainage Less Intensive Technology Enhanced (SAGD LITE) – Field trials are underway to evaluate new SAGD technologies such as solvent addition, surfactant addition, flow control devices and injection control devices to improve cost, SORs, and timely recovery and productivity. Monitoring and evaluation will continue throughout 2016.

Suncor is a founding member of Canada's Oil Sands Innovation Alliance (COSIA), a group of oil sands producers focused on accelerating the pace of environmental performance improvement through collaborative action and innovation.

Suncor is also co-funding Evok Innovations, an investment partnership, which brings together British Columbia's clean technology industry and Alberta's oil and gas sector to advance new technologies directed at environmental and economic investments. The fund supports technological ideas that have reached the development and commercialization stage.

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, Quebec, the U.S. Midwest and the U.S. Rocky Mountain regions and markets in the U.S. Gulf Coast. Diesel production from upgrading operations is sold primarily in Western Canada and the United States, marketed by Suncor's Energy Trading 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 diluted bitumen at Suncor's Edmonton refinery; or (c) selling diluted bitumen directly to third parties. Increased bitumen sales may also be required during upgrading facilities outages. In Situ bitumen production processed by Oil Sands Base upgrading facilities in 2015 increased to 104 mbbls/d or 48% (2014 – 98 mbbls/d or 49%) of total in situ bitumen production.

Sales Volumes and Operating Revenues – Principal Products	2015 mbbls/d	2015 % operating revenues	2014 mbbls/d	2014 % operating revenues
Sweet – Light sweet SCO and diesel (including Syncrude)	**168.1**	**45**	161.4	44
Sour – Light sour SCO and bitumen	**290.2**	**51**	260.3	52
Non-proprietary, byproducts and other operating revenues[1]	**n/a**	**4**	n/a	4
	458.3		421.7	

(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 sales agreements for its proprietary sour SCO, which contain varying terms with respect to pricing, volume, expiry and termination.

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. Suncor has arrangements with Enbridge to store SCO, diluted bitumen and diesel at this facility. 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, the company 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.
- To Suncor's Sarnia refinery on the Enbridge mainline and Lakehead pipeline systems.
- To most major refining hubs via the Enbridge mainline, Express/Platte and Keystone pipeline systems.
- To Suncor's Montreal Refinery on Enbridge's Line 9.

Royalties

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

Effective January 1, 2009, under the New Royalty Framework, royalties for oil sands projects are based on a sliding-scale rate of 25% to 40% of net revenue, subject to a minimum royalty within a range of 1% to 9% of gross revenue. 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 for the minimum rate to the maximum rate at a WTI price of Cdn$120/bbl. A project remains subject to the minimum royalty (the pre-payout phase) until the project's cumulative gross revenue exceed its cumulative costs, including an annual investment allowance (the post-payout phase).

Oil Sands Base and Syncrude

Both Suncor and the co-owners of Syncrude reached separate agreements with the Government of Alberta for the implementation of the New Royalty Framework:

- For the period from January 1, 2010 to December 31, 2015, royalty rates for Oil Sands Base were based on a sliding scale, depending on the Canadian dollar equivalent for WTI, from 25% to 30% of net revenue. Oil Sands Base royalties are also subject to the minimum royalty rate range of 1.0% to 1.2% of gross revenue. In 2015, Suncor incurred royalties at Oil Sands Base mining operations at a rate of 1.2% of gross revenue (2014 – 30% of net revenue) with the decrease primarily due to lower oil prices.
- Syncrude continued paying a bitumen-based royalty on the greater of 1% of gross revenue, or 25% of net revenue, until December 31, 2015. The royalty rate at Syncrude was 1% of gross revenue in 2015 (2014 – 25% of net revenue) with the decrease primarily due to lower oil prices. 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.

In 2015, Oil Sands Base royalties were approximately 1% of Oil Sands Base operating revenues (2014 – 7%). In 2015, Suncor incurred royalties on Syncrude operations averaging approximately 3% of Syncrude operating revenues (2014 – 7%).

Beginning on January 1, 2016, Suncor's Oil Sands Base and Syncrude operations will be subject to the generic royalty regime as set out in the New Royalty Framework.

In Situ

Royalty rates for Suncor's MacKay River and Firebag are based on the New Royalty Framework.

In 2015, Suncor incurred royalties at an average rate of 2% of gross revenue for MacKay River (2014 – 7% of gross revenue) and royalties at an average rate of 2% of gross revenue for Firebag (2014 – 7% of gross revenue), which continues in the pre-payout phase.

Exploration and Production

E&P Canada – Assets and Operations

East Coast Canada

Based in St. John's, Newfoundland and Labrador, this business includes interests in three producing fields and future developments and extensions. Suncor is also involved in exploration drilling for new opportunities. Suncor is the only company in this region with interests in every field currently in production.

Terra Nova

The Terra Nova oilfield is approximately 350 km southeast of St. John's. Terra Nova was discovered in 1984, and was the second oilfield to be developed offshore Newfoundland and Labrador. Operated by Suncor, the production system uses a Floating Production, Storage and Offloading (FPSO) vessel that is moored on location, and has gross production capacity of 180 mbbls/d (68 mbbls/d net 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. The Terra Nova oilfield is divided into three distinct areas, known as the Graben, the East Flank and the Far East. Production from Terra Nova began in January 2002. As at December 31, 2015, there were 30 wells: 17 oil production wells, ten water injection wells and three gas injection wells.

In 2015, Suncor's share of Terra Nova production averaged 14 mbbls/d compared to 17 mbbls/d in 2014. Annual turnaround maintenance was completed at the Terra Nova facility in July 2015, which lasted approximately eight weeks.

Hibernia and the Hibernia Southern Extension Unit (HSEU)

The Hibernia oilfield, encompassing the Hibernia and Ben Nevis Avalon reservoirs, is approximately 315 km southeast of St. John's and was the first field to be developed in the Jeanne d'Arc Basin. Operated by Hibernia Management and Development Company Ltd., the production system is a fixed Gravity Based Structure (GBS) that sits on the ocean floor, and has gross production capacity of 230 mbbls/d (46 mbbls/d net 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. As at December 31, 2015, there were 63 wells: 37 oil production wells, 14 single-zone water injection wells, seven dual-zone water injection wells and five gas injection wells.

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 2015, one production well was completed from the GBS platform and is producing oil, along with two water injection wells. Current development plans include drilling one additional production well from the GBS platform and three additional water injection wells in the excavated subsea drill centre. The number of development and injection wells required may be revised as the development proceeds and uncertainties regarding reservoir capability are resolved. Effective December 1, 2015, Suncor's working interest in HSEU decreased to 19.13% from 19.51%, as part of an interim reset of working interests following HSEU achieving a development milestone.

In 2015, Suncor's share of Hibernia production averaged 18 mbbls/d (2014 – 23 mbbls/d). Turnaround maintenance was completed at Hibernia in October 2015, which lasted approximately five weeks.

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 (39 mbbls/d net 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. As at December 31, 2015, there were 36 wells: 17 oil production wells, 15 water injection wells, one gas injection well and three gas storage wells, with one production well added during the year.

In 2007, the White Rose co-venturers signed an agreement with the Government of Newfoundland and Labrador for the development of the White Rose Extensions, which include the North Amethyst, South White Rose Extension, and West White Rose satellite fields. In May 2010, first oil was achieved at North Amethyst, and development drilling will continue in 2016. Development of the South White Rose Extension began in 2013, with first oil being achieved in June 2015. Development drilling will continue in 2016.

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 September 2011. In late 2014, sanction of the second stage was deferred by the co-owners of the project in response to the current lower crude oil price environment.

In 2015, Suncor's share of White Rose production averaged 12 mbbls/d (2014 – 15 mbbls/d).

Hebron

Discovered in 1980, the Hebron oilfield is located 340 km southeast of St. John's and is operated by ExxonMobil Canada Properties. On December 31, 2012, the Hebron co-owners announced project sanction. Effective January 1, 2016, Suncor's working interest in the Hebron project was reset from 22.729% to 21.034%. 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 (32 mbbls/d net to Suncor). Construction of the Hebron project continued during 2015, with first oil expected in late 2017. At sanction, Suncor's share of the post-sanction project cost estimate was expected to be approximately $2.8 billion.

Other Assets

The Ballicatters oil and gas discovery, located 22 km northeast of Hibernia, was completed in 2011 with Suncor operating the licence. While options to commercialize the discovery continue to be evaluated, uncertainty regarding the long-term plans resulted in the remaining carrying value being charged to earnings in 2015.

During 2014, Suncor entered into an agreement with Shell Canada Limited and ConocoPhillips Canada East Coast Partnership to pursue a deepwater exploration opportunity in the Shelburne Basin, located approximately 250 km offshore Nova Scotia. Through the agreement, Suncor acquired a 20% non-operating interest. During the fourth quarter of 2015, drilling of one exploration well commenced and drilling of a second exploration well is expected to commence in the first half of 2016.

Suncor continues to pursue opportunities offshore Newfoundland and Labrador. During 2014, Suncor was a successful joint bidder with ExxonMobil Canada for exploration licences in the Flemish Pass and Carson Basin, located approximately 500 km off the east coast of Newfoundland. The work commitment on these licences in the Flemish Pass and Carson Basin is over the next five to eight years. The company also holds interests in 50 significant discovery licences and nine other exploration licences offshore in this area.

North America Onshore

The North America Onshore business explores for, develops and produces natural gas, NGLs, crude oil and byproducts in Western Canada. Suncor sold the majority of its natural gas business in 2013, followed by the sale in 2014 of its interests in its Wilson Creek assets in central Alberta. Following these disposals, the retained assets produce approximately 3 mboe/d, primarily natural gas, from the Kobes/Montney assets in northeast B.C., in which Suncor has a 100% working interest.

Suncor also holds undeveloped assets that allow the company to explore long-term opportunities.

E&P International – Assets and Operations

North Sea

Buzzard

The Buzzard oilfield is located in the Outer Moray Firth, 95 km northeast of Aberdeen, Scotland. Operated by Nexen Petroleum U.K. Limited (Nexen U.K.), a subsidiary of China National Offshore Oil Corporation Limited, the Buzzard facilities have gross installed production capacity of approximately 220 mbbls/d (66 mbbls/d net to Suncor) of oil and 80 mmcf/d (24 mmcf/d net 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 and consists of four bridge-linked platforms supporting wellhead facilities, production facilities, living quarters and utilities, as well as sulphur handling. As at December 31, 2015, there were 48 wells: 35 oil and gas production wells and 13 water injection wells. In 2015, Suncor's share of Buzzard production averaged 50 mboe/d (2014 – 47 mboe/d).

Golden Eagle Area Development (GEAD)

The Golden Eagle development operated by Nexen U.K. 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 incorporates a production, utilities and accommodation platform, linked to a separate wellhead platform, with a peak production rate of 70 mboe/d (18 mboe/d net to Suncor) from 21 development wells. First oil was achieved in October 2014 and peak production of approximately 18 mboe/d (net to Suncor) was achieved in 2015. As at December 31, 2015, there were 13 wells: nine oil and gas production wells and four water injection wells. In 2015, Suncor's share of Golden Eagle production averaged 15 mboe/d (2014 – 1 mboe/d). The Golden Eagle co-owners also hold adjacent exploration licences and continue to explore the region.

Other Assets

Other Suncor exploration and appraisal initiatives in the North Sea include:

- Beta discovery (Norway) – Suncor is the operator of the PL375 licence, in which it has an 80% 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. A fourth well was drilled in 2014 and confirmed the location of oil volumes in the area of the discovery. In 2015, the company relinquished the majority of its licences in the area, retaining only the part that includes the discovery. The company continues to work with nearby producing field operators to secure a host to tie-back the Beta discovery.
- Butch discovery (Norway) – In 2011, Centrica plc, the operator of 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 before reaching its intended depth due to wellbore instability. In 2014, two additional wells were drilled to explore for oil in separate fault blocks from the discovery; however, neither well encountered hydrocarbons. The partners continue to evaluate development options, and engineering studies are continuing in 2016.

Suncor continues to pursue other opportunities in the North Sea, the Norwegian Sea and the Barents Sea. The company holds interests in 22 exploration licences in the U.K. and Norwegian sectors of these areas.

Other International

Libya

In Libya, Suncor is a signatory to seven EPSAs with the NOC. Five of the seven EPSAs contain fields with proved and probable reserves, and exploration prospects; the remaining two are exploration EPSAs that do not contain reserves, one of which is to be relinquished following an unsuccessful exploration program. Under the EPSAs, Suncor pays 100% of the exploration costs, 50% of the development costs and 12% of the operating costs. The development, operating and eligible exploration costs are recovered through a 12% share of production (Cost Recovery oil). Any Cost Recovery oil remaining after Suncor's costs have been recovered is referred to as excess petroleum, and is shared between Suncor and the NOC based on several factors. The EPSAs expire on December 31, 2032, but include an initial five-year extension through the end of 2037. 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.

Since 2013, production and liftings in Libya have been intermittent due to political unrest and closure of two of the main seaport terminals. Despite intermittent production in 2015 for which Suncor received no payment, the political situation in Libya has not improved, and as a result of continued uncertainty regarding a return to normal operations, as well as damages to production facilities that were confirmed during the fourth quarter of 2015, the remaining value of Suncor's assets in Libya were written down in 2015. Suncor continues to maintain its office in Libya, its rights to the underlying contracts, and meet its commitments under the terms of the EPSAs. The estimated cost of Suncor's remaining exploration work program commitment at December 31, 2015 is US$359 million.

In 2015, Suncor's share of production in Libya averaged 3 mbbls/d (2014 – 7 mbbls/d).

Syria

In December 2011, amid continuing unrest in Syria, sanctions were imposed and Suncor declared force majeure under its contractual obligations, suspending its operations in the country. 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 damage. As a result of continued uncertainty about Suncor's future in the country, the remaining value of the Suncor assets was impaired in 2013.

Prior to December 2011, Suncor conducted its Syrian operations pursuant to a PSC, where the company paid 100% of the development costs and recovered these costs from a 40% share of production after deduction of royalties of 12.5%. This petroleum revenue is referred to as Cost Recovery petroleum. The amount by which Cost Recovery petroleum exceeded recoverable cost is referred to as Excess Cost Recovery petroleum; 50% of this amount is due to the General Petroleum Corporation (GPC) and the remaining 50% was shared between Suncor and the GPC according to a profit-sharing schedule.

Sales of Principal Products

Oil and gas production from East Coast Canada, the North Sea and from North America Onshore is either marketed by Suncor's Energy Trading business acting as a marketing agent, or sold to the company's 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 all made on a spot basis, and incorporate pricing that is generally determined on a daily or monthly basis in relation to a specified market reference price.

In Libya, crude oil is marketed by the NOC on behalf of Suncor.

Exploration and Production Sales Summary:

	2015		2014	
Sales Volumes	mboe/d	% operating revenues	mboe/d	% operating revenues
E&P Canada				
Crude oil and NGLs	**43.1**	**40**	55.2	53
Natural gas	**3.0**	**1**	2.8	1
E&P International				
Crude oil and NGLs	**63.0**	**59**	47.2	46
Natural gas	**1.5**	**0**	0.9	0
Total Exploration and Production				
Crude oil and NGLs	**106.1**	**99**	102.4	99
Natural gas	**4.5**	**1**	3.7	1

Distribution of Products

- East Coast Canada – field production is transported by shuttle tanker from offshore installations 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, the U.S., Europe, Latin America and Asia. 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.
- North America Onshore – gas production is typically sold at Station 2, part of the Spectra B.C. transmission system. Suncor also holds firm capacity on the TransCanada PipeLines Gas Transmission Northwest Pipeline, which enables Suncor to deliver natural gas to the Pacific Northwest and California markets.
- Buzzard – crude oil is transported via the third-party operated Forties Pipeline System to the Hound Point terminal in Scotland and sold as part of the Forties Blend crude stream. Natural gas is transported via the third-party operated Frigg Pipeline System to the St. Fergus Gas Terminal in Scotland.
- Golden Eagle – crude oil is transported to the third-party operated Flotta Terminal in the Orkney Islands in Scotland where it is shipped to market as part of the Flotta Gold blend. Natural gas is transported via the third-party operated SAGE Pipeline System to the St. Fergus Gas Terminal in Scotland.

Royalties

East Coast Canada

The Terra Nova royalty consists of a sliding-scale basic royalty payable, with two tiers of incremental royalties. The basic royalty is now capped at 10% of gross field revenue. The tier one royalty is the greater of the basic royalty or 30% of net revenue, and became payable in 2005. Net revenue is gross revenue adjusted for eligible operating and capital costs. The tier two royalty, equal to an additional

12.5% of net revenue, became payable in 2008. During 2015, Terra Nova royalties averaged 20% of gross revenue (2014 – 21% of gross revenue).

The Hibernia royalty agreement for production from the original oilfields and the AA Block consists of a sliding-scale basic royalty, two tiers of incremental royalties, and an additional net profits interest (NPI). The basic royalty is now capped at 5% of gross revenue. The tier one royalty, which became payable in 2009, is the greater of the basic royalty or 30% of net revenue. The tier two royalty is an additional 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 of 12.5% of net revenue. The NPI, which also became payable in 2009, is an additional 10% of net revenue. Limited production from the HSEU began in 2011. The HSEU has a similar royalty structure (gross, tier one and tier two) to that described above for Hibernia. Currently, Suncor is only subject to a 5% gross royalty. HSEU production will be subject to an additional 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 royalty. For the portion of the HSEU that is contained within the original Hibernia licence area, but will be developed with the new subsea facilities, production will be subject to an additional tier three royalty that ranges between 7.5% and 12.5% of net revenue, depending on the price for WTI. During 2015, Hibernia (including the HSEU) royalties and NPI combined to average 25% of gross revenue (2014 – 33% of gross revenue).

The White Rose royalty for the base project consists of a sliding-scale basic royalty, with two tiers of incremental royalties. The basic royalty is now capped at 7.5% of gross field revenue. The tier one royalty is the greater of the basic royalty, or 20% of net revenue, and became payable in 2007. The tier two royalty, equal to an additional 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 US$50/bbl. Tier one and tier three royalties for the White Rose Extensions became payable in 2014. During 2015, total White Rose royalties averaged 11% of gross revenue (2014 – 14% of gross revenue).

E&P 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 50% income tax rate. During 2015, the U.K. government enacted a decrease in the supplementary charge rate on oil and gas profits in the North Sea that reduced the statutory tax rate on Suncor's earnings in the U.K. from 62% to 50%. For operations in Libya, all government interests, except for income taxes, are presented as royalties.

Refining and Marketing

Refining and Supply – Assets and Operations Eastern North America

Montreal Refinery

The Montreal refinery has a crude oil capacity of 137 mbbls/d, processing primarily 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 supplied via the Portland-Montreal Pipeline, by marine transportation, by rail for inland crudes and now, Enbridge's Line 9. The Montreal refinery received inland crude volumes averaging 39 mbbls/d through 2015.

Production yield from the Montreal refinery includes gasoline, distillate, heavy fuel oil, solvents, 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.

Sarnia Refinery

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, kerosene, and jet and diesel fuels, 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.

Other Facilities

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 321,000 metric tonnes in 2015 (2014 – 366,000 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, located in Mississauga, Ontario, is the largest producer of lubricant base stocks in Canada. In 2015, the plant produced approximately 766 million litres of lubricant base stocks. Feedstock for the lubricants facility comes from Suncor's Montreal refinery and other purchase contracts.

Western North America

Edmonton Refinery

The Edmonton refinery has a crude oil capacity of 142 mbbls/d and has the potential to run entirely on feedstock sourced from oil sands. 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 Wood Buffalo 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, distillate and other light oils, 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.

Commerce City Refinery

The Commerce City refinery has a crude oil capacity of 98 mbbls/d. The refinery processes primarily conventional crude oil, and has processed up to 16 mbbls/d of sour SCO and diluted bitumen from Suncor's Oil Sands Base operations. A majority of crude feedstock is supplied from sources in the U.S., including 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 61% 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 paving-grade 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.

Other Facilities

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, 2015 and 2014.

Average Daily Crude Throughput	Montreal		Sarnia		Edmonton		Commerce City	
(mbbls/d, except as noted)	**2015**	2014	**2015**	2014	**2015**	2014	**2015**	2014
Oil Sands Base sweet synthetic	—	—	**8.4**	11.5	**47.7**	41.3	**0.6**	0.6
Oil Sands Base sour synthetic	—	—	**31.2**	24.1	**47.6**	63.2	**10.6**	10.8
Other synthetic	**16.7**	—	**21.7**	15.4	**27.6**	26.8	**10.6**	8.7
East Coast Canada light conventional(1)	**14.1**	23.2	—	—	—	—	—	—
Other light conventional	**96.1**	79.4	**9.0**	5.0	—	—	**64.3**	65.8
Sour conventional	**0.4**	4.9	**10.3**	19.8	—	—	**10.7**	11.0
Heavy conventional	**0.1**	15.6	—	—	—	—	**1.3**	—
Total	**127.4**	123.1	**80.6**	75.8	**122.9**	131.3	**98.1**	96.9
Utilization(2) (%)	**93**	90	**95**	89	**87**	92	**100.2**	99

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

(2) Refinery utilizations based on crude 2015 processing capacities (in mbbls/d): Montreal – 137; Sarnia – 85; Edmonton – 142; and Commerce City – 98.

Refined petroleum production yield mix	Montreal		Sarnia		Edmonton		Commerce City	
(%)	**2015**	2014	**2015**	2014	**2015**	2014	**2015**	2014
Gasoline	**42**	42	**48**	47	**48**	41	**48**	47
Distillates	**36**	35	**38**	34	**48**	54	**35**	35
Other	**22**	23	**14**	19	**4**	5	**17**	18

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 certain pipelines, including the following:

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

Marketing – Assets and Operations

Suncor's retail service station network operates nationally in Canada primarily under the Petro-Canada™ brand. As at December 31, 2015, this network consisted of 1,484 outlets across Canada. In addition, refined products are marketed through independent dealers and joint arrangements. Suncor's Canadian retail network had sales of gasoline motor fuels averaging approximately 4.8 million litres per site in 2015 (2014 – 4.8 million litres) and attracted an estimated 17.8% share (2014 – 17.3%) of the national retail urban market.

Suncor's Colorado retail network consists of 44 owned outlets branded Shell , Exxon and Mobil , and product supply agreements with a larger network of Shell -branded sites. During 2015, the Phillips 66 -branded sites were rebranded as Exxon and Mobil .

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 refined products directly to large industrial and commercial customers and independent marketers.

Retail Summary:

Locations	As at December 31 2015	2014
Retail Service Stations – Canada		
Petro-Canada™-branded	**1 484**	1 465
Sunoco™-branded	**1**	1
	1 485	1 466
Retail Service Stations – Colorado		
Shell -branded retail service stations	**38**	38
Exxon -branded retail service stations	**5**	—
Mobil -branded retail service stations	**1**	—
Phillips 66 -branded retail service stations	**—**	6
	44	44
Wholesale Cardlock Sites – Canada		
Petro-Canada™-branded cardlock sites (PETRO-PASS)	**280**	266

Sales Volumes	2015 mbbls/d	2015 % operating revenues	2014 mbbls/d	2014 % operating revenues
Gasoline (includes motor and aviation gasoline)				
Eastern North America	**118.9**		120.6	
Western North America	**127.3**		122.8	
	246.2	**47**	243.4	44
Distillates (includes diesel and heating oils, and aviation jet fuels)				
Eastern North America	**91.1**		81.9	
Western North America	**106.9**		117.8	
	198.0	**38**	199.7	39
Other (includes heavy fuel oil, asphalts, lubricants, petrochemicals, other)				
Eastern North America	**52.8**		58.2	
Western North America	**26.3**		30.4	
	79.1	**15**	88.6	17
	523.3		531.7	

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 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 – and has trading offices in Canada, the U.K. and the U.S. Energy Trading provides commodity supply, transportation, storage and pricing solutions. The company's 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 and E&P 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.

The Energy Trading business supports the company's Refining and Marketing business by optimizing the supply of crude and NGLs feedstock to the four refineries, managing crude inventory levels during refinery turnarounds and periods of unplanned maintenance as well as managing external impacts from pipeline disruptions.

Renewable Energy

Suncor has invested in Canada's biofuels industry since 2006. Suncor operates Canada's largest ethanol facility, the St. Clair Ethanol plant in the Sarnia-Lambton region of Ontario with a nameplate capacity of 400 million litres per year. In 2015, the plant produced 417.9 million litres of ethanol (2014 – 412.0 million litres). In 2014, Suncor also invested in biodiesel technology to capture a production cost advantage, through interests in both a technology company and the retrofit of a biodiesel plant, which is expected to begin production in early 2016.

Suncor's renewable energy interests include six wind power projects in operation with a gross generating capacity of 287 MW, including the Cedar Point wind farm which commenced operations in 2015. Total capacity decreased from 295 MW in 2014 due to the sale of the Wintering Hills and Kent Breeze wind farm assets during 2015. Suncor continues to evaluate new opportunities to build its renewable energy portfolio with potential wind and solar power projects that are in various stages of the evaluation process.

Suncor's wind power projects:

Wind Power Projects		Ownership Interest (%)	Gross (MW)	Turbines	Completed
Operated by Suncor					
Adelaide	Strathroy, Ontario	75.0	40	18	2014
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
Cedar Point	Lambton County, Ontario	50.0	100	46	2015

SUNCOR EMPLOYEES

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

As of December 31	2015	2014
Oil Sands[1]	**6 008**	6 025
Exploration and Production	**360**	489
Refining and Marketing	**3 437**	3 460
Corporate, Energy Trading and Renewable Energy	**3 385**	3 732
Total	**13 190**	13 706

(1) Includes employees related to the Fort Hills operations.

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

Approximately 34% of the company's employees were covered by collective agreements at the end of 2015. The majority of collective agreements, covering approximately 4,152 employees represented by Unifor, expire in 2016. Collective agreements with the United Steel Workers Union, representing approximately 266 employees at the Commerce City refinery, and with the Sunoco Employees' Bargaining Association, representing approximately 204 employees at the Sarnia refinery, were successfully renewed in 2015.

SOCIAL AND ENVIRONMENTAL 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 or confirmation that any instance of non-compliance has been discussed and resolved with the individual's supervisor. Compliance is then reported to Suncor's Audit Committee. In 2015, the Trade Relations Policy of the Code was amended to allow some greater flexibility to the business but still ensure that competition law risks are assessed and appropriate safeguards are implemented as necessary. A copy of the Code is available on Suncor's website at www.suncor.com.

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. 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 states that successful stakeholder engagement guides informed decision-making, resolving issues with timely, cost-effective and mutually beneficial solutions, building stronger communities and supporting shared learning.

Suncor has a Canadian Aboriginal Relations Policy, which affirms Suncor's desire to work in collaboration with 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 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 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 interests regarding the opportunities and impacts of energy development on communities and on their traditional and current uses of lands and resources.

Suncor has an Environment, Health and Safety (EH&S) policy, which affirms Suncor's commitment 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 states that Suncor management is responsible for ensuring that employees and contractors 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.

The Environment, Health, Safety and Sustainable Development Committee of the Board of Directors meets quarterly to review Suncor's effectiveness in meeting its EH&S obligations. 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.

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

The aforementioned policies are reviewed annually and are accessible to employees and contractors on the company's intranet. Additional workshops and training sessions are also conducted as warranted throughout the year. Information regarding the policies is provided for employees primarily though feature articles on the company's intranet. The Aboriginal Relations Policy has Cree and Dene audio translations. Training is provided for employees and contract workers whose roles require interaction with Aboriginal communities.

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 25, 2016, with an effective date of December 31, 2015. Reserves evaluations have not been updated since the effective date and, thus, do not reflect changes in our reserves since that date. The preparation date of the information is February 19, 2016.

Disclosure of Reserves Data

Suncor is subject to the reporting requirements of Canadian securities regulatory authorities, including the reporting of reserves data in accordance with National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities* (NI 51-101).

The reserves data included 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), 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 and its natural gas assets located in Western Canada (collectively, E&P Canada), and conventional assets offshore the U.K. (North Sea) and in Libya (Other International), is based upon evaluations conducted by Sproule Associates Limited or Sproule International Limited (collectively, Sproule), 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.

The reserves data summarizes Suncor's SCO, bitumen, light crude oil and medium crude oil combined, heavy crude oil, conventional natural gas and NGLs reserves and the net present values of future net revenues for these reserves using forecast prices and costs prior to provision for interest and general and administrative expense.

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 crude oil and medium crude oil, heavy crude oil, conventional natural gas and NGLs reserves provided herein will be recovered. Actual SCO, bitumen, light crude oil and medium crude oil, heavy crude oil, conventional natural gas and NGLs volumes recovered may be greater than or less than the estimates provided herein. Readers should review the Glossary of Terms and Abbreviations, 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 Risk Factors and Uncertainties Affecting Reserves

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 is 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 development. For example, 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 (however, this is generally not the case for assets under PSCs, as described in the Notes to Reserves Data Tables in relation to the economic interest method used to determine entitlement reserves). Royalty regimes and environmental regulations and other regulatory changes 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 may result in an increase to reserves. Should political unrest continue in Libya, this may result in unfavourable changes to Suncor's reserves in that country.

While the above factors, and many others, are relevant, certain judgments and assumptions are always required. As new information becomes available, these areas are reviewed and revised accordingly.

The reserves included in this AIF represent estimates only. There are numerous uncertainties inherent in estimating quantities and quality of these reserves, including many factors beyond our control. In general, estimates of economically recoverable reserves and the future net cash flow from these assets are based upon a number of variable factors and assumptions, such as production forecasts, regulations, pricing, the timing and amount of capital expenditures, future royalties, future operating costs, and yield rates for upgraded production of synthetic crude oil from bitumen – all of which may vary considerably from actual results and may be affected by many of the factors identified under Industry Conditions and Risk Factors herein. The accuracy of any reserves estimate is a matter of interpretation and judgment and is a function of the quality and quantity of available data, which may have been gathered over time. For these reasons, estimates of the economically recoverable reserves and classification of such reserves based on the certainty of recovery, prepared by different engineers or by the same engineers at different times, may vary.

Reserves estimates are based upon geological assessment, including drilling and laboratory tests. Mining reserves estimates also consider production capacity and upgrading yields, mine plans, operating life and regulatory constraints. In Situ reserves and estimates are also based upon the testing of core samples and seismic operations and demonstrated commercial success of in situ processes. Our actual production, revenues, royalties, taxes, and development and operating expenditures with respect to our reserves will vary from such estimates, and such variances could be material. Production performance subsequent to the date of the estimate may justify revision, either upward or downward, if material.

The reserves evaluations are based in part on the assumed success of activities we intend to undertake in future years. The reserves and estimated cash flow to be derived from the reserves contained in the reserves evaluations may be increased or reduced to the extent that such activities do or do not achieve the level of success assumed in the reserves evaluations.

Oil and Gas Reserves Tables and Notes

Summary of Oil and Gas Reserves(1)(2)(3)
as at December 31, 2015
(forecast prices and costs)

	SCO(4) (mmbbls)		Bitumen (mmbbls)		Light Crude & Medium Crude Oil (mmbbls)		Conventional Natural Gas(5)(6) (bcfe)		Total(7) (mmboe)	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Proved Developed Producing										
Mining	1 673	1 498	—	—	—	—	—	—	1 673	1 498
In Situ	186	179	122	117	—	—	—	—	308	296
E&P Canada	—	—	—	—	56	44	32	29	61	49
Total Canada	1 859	1 678	122	117	56	44	32	29	2 043	1 843
North Sea	—	—	—	—	58	58	3	3	58	58
Other International	—	—	—	—	—	—	—	—		
Total Proved Developed Producing	**1 859**	**1 678**	**122**	**117**	**114**	**101**	**35**	**32**	**2 101**	**1 901**
Proved Developed Non-Producing										
Mining	—	—	—	—	—	—	—	—	—	—
In Situ	—	—	3	3	—	—	—	—	3	3
E&P Canada	—	—	—	—	—	—	2	2	—	—
Total Canada	—	—	3	3	—	—	2	2	3	3
North Sea	—	—	—	—	—	—	—	—	—	—
Other International	—	—	—	—	87	27	—	—	87	27
Total Proved Developed Non-Producing	**—**	**—**	**3**	**3**	**87**	**27**	**2**	**2**	**90**	**29**
Proved Undeveloped										
Mining	—	—	1 052	943	—	—	—	—	1 052	943
In Situ	584	494	741	629	—	—	—	—	1 324	1 124
E&P Canada	—	—	—	—	22	19	—	—	51	48
Total Canada	584	494	1 792	1 572	22	19	—	—	2 427	2 115
North Sea	—	—	—	—	10	10	1	1	10	10
Other International	—	—	—	—	51	13	—	—	51	13
Total Proved Undeveloped	**584**	**494**	**1 792**	**1 572**	**82**	**42**	**1**	**1**	**2 488**	**2 138**
Proved										
Mining	1 673	1 498	1 052	943	—	—	—	—	2 725	2 441
In Situ	769	673	866	749	—	—	—	—	1 634	1 422
E&P Canada	—	—	—	—	78	63	34	30	113	97
Total Canada	2 442	2 171	1 917	1 692	78	63	34	30	4 473	3 961
North Sea	—	—	—	—	67	67	4	4	68	68
Other International	—	—	—	—	138	40	—	—	138	40
Total Proved	**2 442**	**2 171**	**1 917**	**1 692**	**283**	**171**	**38**	**34**	**4 679**	**4 069**
Probable										
Mining	494	429	542	461	—	—	—	—	1 035	890
In Situ	1 257	1 020	305	241	—	—	—	—	1 561	1 260
E&P Canada	—	—	—	—	129	98	13	11	213	171
Total Canada	1 750	1 448	846	702	129	98	13	11	2 810	2 321
North Sea	—	—	—	—	26	26	2	2	26	26
Other International	—	—	—	—	95	38	—	—	95	38
Total Probable	1 750	1 448	846	702	251	161	15	13	2 931	2 385
Proved Plus Probable										
Mining	2 167	1 927	1 593	1 404	—	—	—	—	3 760	3 331
In Situ	2 025	1 692	1 170	990	—	—	—	—	3 196	2 683
E&P Canada	—	—	—	—	207	161	47	42	326	268
Total Canada	4 192	3 619	2 764	2 394	207	161	47	42	7 282	6 281
North Sea	—	—	—	—	94	94	6	6	94	94
Other International	—	—	—	—	233	78	—	—	233	78
Total Proved Plus Probable	**4 192**	**3 619**	**2 764**	**2 394**	**534**	**332**	**53**	**47**	**7 610**	**6 454**

Please see Notes (1) through (7) at the end of the reserves data section for important information about volumes in this table.

Reconciliation of Gross Reserves[1][2][3]
as at December 31, 2015
(forecast prices and costs)

	SCO[4]			Bitumen			Light Crude & Medium Crude Oil			Conventional Natural Gas[5][6]			Total[7]		
	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable
	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	bcfe	bcfe	bcfe	mmboe	mmboe	mmboe
Mining															
December 31, 2014	1 792	498	2 291	845	408	1 253	—	—	—	—	—	—	2 637	907	3 543
Extensions & Improved Recovery[8]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Technical Revisions[9]	(23)	(5)	(27)	—	27	27	—	—	—	—	—	—	(23)	22	—
Discoveries[10]	—	—	—	—	—	—	—	—	—	—	—	—	—		—
Acquisitions	—	—	—	207	107	314	—	—	—	—	—	—	207	107	314
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors[11]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Production	(96)	—	(96)	—	—	—	—	—	—	—	—	—	(96)	—	(96)
December 31, 2015	**1 673**	**494**	**2 167**	**1 052**	**542**	**1 593**	**—**	**—**	**—**	**—**	**—**	**—**	**2 725**	**1 035**	**3 760**
In Situ															
December 31, 2014	698	1 156	1 854	994	328	1 322	—	—	—	—	—	—	1 692	1 485	3 177
Extensions & Improved Recovery[8]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Technical Revisions[9]	100	101	201	(86)	(24)	(110)	—	—	—	—	—	—	14	77	91
Discoveries[10]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors[11]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Production	(30)	—	(30)	(42)	—	(42)	—	—	—	—	—	—	(72)	—	(72)
December 31, 2015	**769**	**1 257**	**2 025**	**866**	**305**	**1 170**	**—**	**—**	**—**	**—**	**—**	**—**	**1 634**	**1 561**	**3 196**
E&P Canada															
December 31, 2014	—	—	—	—	—	—	110	230	340	50	18	68	119	233	351
Extensions & Improved Recovery[8]	—	—	—	—	—	—	—	5	5	—	—	—	—	5	5
Technical Revisions[9]	—	—	—	—	—	—	(15)	(106)	(121)	(1)	(3)	(4)	14	(25)	(11)
Discoveries[10]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors[11]	—	—	—	—	—	—	—	—	—	(8)	(2)	(10)	(1)	—	(2)
Production	—	—	—	—	—	—	(17)	—	(17)	(7)	—	(7)	(18)	—	(18)
December 31, 2015	**—**	**—**	**—**	**—**	**—**	**—**	**78**	**129**	**207**	**34**	**13**	**47**	**113**	**213**	**326**
Total Canada															
December 31, 2014	2 491	1 655	4 145	1 838	737	2 575	110	230	340	50	18	68	4 447	2 624	7 071
Extensions & Improved Recovery[8]	—	—	—	—	—	—	—	5	5	—	—	—	—	5	5
Technical Revisions[9]	78	96	174	(86)	3	(83)	(15)	(106)	(121)	(1)	(3)	(4)	6	74	80
Discoveries[10]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Acquisitions	—	—	—	207	107	314	—	—	—	—	—	—	207	107	314
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors[11]	—	—	—	—	—	—	—	—	—	(8)	(2)	(10)	(1)	—	(2)
Production	(126)	—	(126)	(42)	—	(42)	(17)	—	(17)	(7)	—	(7)	(186)	—	(186)
December 31, 2015	**2 442**	**1 750**	**4 192**	**1 917**	**846**	**2 764**	**78**	**129**	**207**	**34**	**13**	**47**	**4 473**	**2 810**	**7 282**

Please see Notes (1) through (11) at the end of the reserves data section for important information about volumes in this table.

Reconciliation of Gross Reserves[1][2][3] *(continued)*
as at December 31, 2015
(forecast prices and costs)

	SCO[4]			Bitumen			Light Crude & Medium Crude Oil			Conventional Natural Gas[5][6]			Total[7]		
	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable
	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	bcfe	bcfe	bcfe	mmboe	mmboe	mmboe
North Sea															
December 31, 2014	—	—	—	—	—	—	91	37	128	3	2	5	91	38	129
Extensions & Improved Recovery[8]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Technical Revisions[9]	—	—	—	—	—	—	1	(12)	(10)	4	—	4	2	(12)	(10)
Discoveries[10]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors[11]	—	—	—	—	—	—	(2)	1	(1)	—	—	—	(2)	1	(1)
Production	—	—	—	—	—	—	(23)	—	(23)	(4)	—	(4)	(24)	—	(24)
December 31, 2015	**—**	**—**	**—**	**—**	**—**	**—**	**67**	**26**	**94**	**4**	**2**	**6**	**68**	**26**	**94**
Other International															
December 31, 2014	—	—	—	—	—	—	142	111	253	—	—	—	142	111	253
Extensions & Improved Recovery[8]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Technical Revisions[9]	—	—	—	—	—	—	(1)	(17)	(18)	—	—	—	(1)	(17)	(18)
Discoveries[10]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors[11]	—	—	—	—	—	—	(2)	1	(1)	—	—	—	(2)	1	(1)
Production	—	—	—	—	—	—	(1)	—	(1)	—	—	—	(1)	—	(1)
December 31, 2015	**—**	**—**	**—**	**—**	**—**	**—**	**138**	**95**	**233**	**—**	**—**	**—**	**138**	**95**	**233**
Total															
December 31, 2014	2 491	1 655	4 145	1 838	737	2 575	343	378	721	53	20	73	4 681	2 773	7 454
Extensions & Improved Recovery[8]	—	—	—	—	—	—	—	5	5	—	—	—	—	5	5
Technical Revisions[9]	78	96	174	(86)	3	(83)	(15)	(135)	(150)	3	(3)	1	7	45	52
Discoveries[10]	—	—	—	—	—	—	—	—	—	—	—	—	—		
Acquisitions	—	—	—	207	107	314	—	—	—	—	—	—	207	107	314
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors[11]	—	—	—	—	—	—	(4)	2	(2)	(8)	(2)	(10)	(5)	1	(4)
Production	(126)	—	(126)	(42)	—	(42)	(41)	—	(41)	(11)	—	(11)	(211)	—	(211)
December 31, 2015	**2 442**	**1 750**	**4 192**	**1 917**	**846**	**2 764**	**283**	**251**	**534**	**38**	**15**	**53**	**4 679**	**2 931**	**7 610**

Please see Notes (1) through (11) at the end of the reserves data section for important information about volumes in this table.

Notes to Reserves Data Tables

as at December 31, 2015

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

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

(3) Other International is comprised of quantities of crude oil in Libya which are expected to be produced under EPSAs. Under these EPSAs, net proved and probable reserves have been determined using the economic interest method. See the Reserves Categories section for a description of the economic interest method.

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

(5) All conventional natural gas, other than immaterial amounts of NGLs (0.4 mmbbls of total proved and 0.6 mmbbls of total proved plus probable NGLs).

(6) Despite a change in the NI 51-101 definition of Natural Gas, natural gas volumes have been reconciled as the associated assets are the same as previously reported.

(7) Total gross volumes for E&P Canada include quantities of heavy crude oil as follows: Proved Undeveloped of 30 mmbbls, Proved of 30 mmbbls, Probable of 82 mmbbls and Proved Plus Probable of 111 mmbbls. Total net volumes for E&P Canada include quantities of heavy crude oil as follows: Proved Undeveloped of 29 mmbbls, Proved of 29 mmbbls, Probable of 71 mmbbls and Proved Plus Probable of 100 mmbbls. For the year ended December 31, 2014, Suncor had no reserves reportable for Heavy Oil. For the year ended December 31, 2015, and for the purposes of the reconciliation, all reserves added in the Heavy Oil category were the result of Technical Revisions.

(8) Extensions & Improved Recovery are additions to the reserves resulting from step-out drilling, infill drilling and implementation of improved recovery schemes. Negative volumes, if any, for probable reserves result from the transfer of probable reserves to proved reserves.

(9) Technical Revisions include changes in previous estimates resulting from new technical data or revised interpretations. In the case of In Situ, a decrease in probable bitumen reserves and an increase in SCO reserves is a result of a planned increase in upgraded Firebag volumes over the forecast period.

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

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

Definitions for Reserves Data Tables

In the tables set forth above and elsewhere in this AIF, the following definitions and other notes are applicable:

Gross means:

(a) in relation to Suncor's interest in production or reserves, Suncor's working-interest share before deduction of royalties and without including any royalty interests of Suncor;

(b) in relation to wells, the total number of wells in which Suncor has a working interest; and

(c) in relation to properties, the total area of properties in which Suncor has an interest.

Net means:

(a) in relation to Suncor's interest in production or reserves, Suncor's working-interest share after deduction of royalty obligations, plus the company's royalty interests in production and reserves;

(b) in relation to wells, the number of wells obtained by aggregating Suncor's working interest in each of the company's gross wells; and

(c) in relation to Suncor's interest in a property, the total area in which Suncor has an interest multiplied by the working interest owned by Suncor.

Reserves Categories

The reserves estimates presented are based on the definitions and guidelines contained in the Canadian Oil and Gas Evaluation (COGE) Handbook. A summary of those definitions is set forth below.

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on analyses of drilling, geological, geophysical and engineering data, the use of established technology, and specified economic conditions, which are generally accepted as being reasonable.

Reserves are classified according to the degree of certainty associated with the estimates:

Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves. Proved reserves estimates should target at least a 90% probability that the quantities actually recovered will equal or exceed the estimate.

Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves. That is, proved plus probable reserves estimates should target at least a 50% probability that the quantities actually recovered will equal or exceed the estimate.

Other criteria that must also be met for the categorization of reserves are provided in the COGE Handbook.

Proved and probable reserves categories may be divided into developed and undeveloped categories:

Developed reserves are those reserves that are expected to be recovered (i) from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production, or (ii) through installed extraction equipment and infrastructure that is operational at the time of the reserves estimate, if the extraction is by means not involving a well. The developed category may be subdivided into producing and non-producing.

(a) Developed producing reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

(b) Developed non-producing reserves are those reserves that either have not been on production, or have previously been on production but are shut in, and the date of resumption of production is unknown.

Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves category (proved or probable) to which they are assigned.

In multi-well pools, it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

In the **economic interest method** used for PSCs, Suncor's share of profit revenue plus cost recovery revenue is divided by the associated oil or gas price forecast to determine Suncor's net volume entitlement, or **entitlement reserves**. The entitlement reserves are then adjusted to include reserves relating to income taxes payable by the national oil company on behalf of Suncor. Under this method, reported reserves will increase as commodity prices decrease (and vice versa).

Future Net Revenues Tables and Notes(1)

Net Present Value of Future Net Revenues Before Income Taxes
as at December 31, 2015
(forecast prices and costs)

	(in $ millions, discounted at % per year)					Unit Value(2)
	0%	5%	10%	15%	20%	($/boe)
Proved Developed Producing						
Mining	19 220	15 149	9 715	6 233	4 078	6.48
In Situ	6 317	5 602	4 999	4 495	4 072	16.87
E&P Canada	782	919	952	940	909	19.67
Total Canada	26 318	21 670	15 666	11 668	9 060	8.50
North Sea	1 962	1 887	1 782	1 672	1 568	30.68
Other International	—	—	—	—	—	—
Total Proved Developed Producing	28 280	23 557	17 448	13 340	10 628	9.18
Proved Developed Non-Producing						
Mining	—	—	—	—	—	—
In Situ	59	65	67	67	66	31.58
E&P Canada	2	2	1	1	1	4.84
Total Canada	61	67	68	68	67	28.35
North Sea	—	—	—	—	—	—
Other International	1 224	879	660	514	412	24.44
Total Proved Developed Non-Producing	1 285	946	729	582	479	24.76
Proved Undeveloped						
Mining	15 152	4 185	388	(1 157)	(1 867)	0.41
In Situ	32 294	16 549	9 132	5 317	3 202	8.13
E&P Canada	1 102	623	288	56	(104)	5.95
Total Canada	48 548	21 357	9 808	4 216	1 230	4.64
North Sea	217	175	142	115	93	14.23
Other International	220	51	(37)	(83)	(105)	(2.80)
Total Proved Undeveloped	48 985	21 584	9 913	4 248	1 218	4.64
Proved						
Mining	34 372	19 333	10 102	5 076	2 211	4.14
In Situ	38 670	22 216	14 198	9 879	7 340	9.98
E&P Canada	1 885	1 544	1 241	997	806	12.78
Total Canada	74 927	43 094	25 542	15 952	10 357	6.45
North Sea	2 179	2 062	1 924	1 787	1 661	28.27
Other International	1 444	930	623	431	307	15.44
Total Proved	78 549	46 086	28 089	18 171	12 325	6.90
Probable						
Mining	34 288	10 345	4 789	2 870	1 990	5.38
In Situ	76 762	19 253	6 866	3 457	2 245	5.45
E&P Canada	12 309	7 694	5 201	3 731	2 798	30.47
Total Canada	123 359	37 291	16 855	10 058	7 033	7.26
North Sea	1 659	1 380	1 149	966	824	43.48
Other International	3 869	2 120	1 256	795	531	33.42
Total Probable	128 887	40 790	19 260	11 819	8 388	8.08
Proved Plus Probable						
Mining	68 661	29 678	14 891	7 946	4 201	4.47
In Situ	115 432	41 469	21 064	13 336	9 585	7.85
E&P Canada	14 194	9 238	6 442	4 728	3 604	24.06
Total Canada	198 287	80 385	42 398	26 010	17 390	6.75
North Sea	3 838	3 442	3 073	2 754	2 485	32.52
Other International	5 312	3 050	1 879	1 226	838	24.11
Total Proved Plus Probable	207 436	86 877	47 349	29 990	20 713	7.34

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

Net Present Value of Future Net Revenues After Income Taxes
as at December 31, 2015
(forecast prices and costs)

	(in $ millions, discounted at % per year)				
	0%	5%	10%	15%	20%
Proved Developed Producing					
Mining	12 862	11 447	7 445	4 777	3 105
In Situ	4 981	4 426	3 953	3 556	3 223
E&P Canada	782	919	952	940	909
Total Canada	18 624	16 792	12 350	9 273	7 237
North Sea	847	819	776	730	686
Other International	—	—	—	—	—
Total Proved Developed Producing	19 472	17 611	13 126	10 003	7 923
Proved Developed Non-Producing					
Mining	—	—	—	—	—
In Situ	30	38	42	44	44
E&P Canada	2	2	1	1	1
Total Canada	32	40	43	45	45
North Sea	—	—	—	—	—
Other International	440	322	246	194	158
Total Proved Developed Non-Producing	472	362	289	239	203
Proved Undeveloped					
Mining	11 850	3 043	(60)	(1 339)	(1 933)
In Situ	23 278	11 667	6 259	3 509	2 000
E&P Canada	1 086	615	284	54	(106)
Total Canada	36 214	15 324	6 483	2 224	(39)
North Sea	138	116	98	83	71
Other International	72	(28)	(81)	(108)	(120)
Total Proved Undeveloped	36 424	15 412	6 500	2 199	(88)
Proved					
Mining	24 712	14 490	7 385	3 438	1 172
In Situ	28 288	16 130	10 255	7 109	5 267
E&P Canada	1 870	1 536	1 237	995	805
Total Canada	54 870	32 156	18 877	11 542	7 243
North Sea	986	935	874	813	757
Other International	512	294	165	86	38
Total Proved	56 368	33 385	19 915	12 441	8 038
Probable					
Mining	25 728	7 577	3 485	2 115	1 503
In Situ	55 845	13 906	4 991	2 555	1 687
E&P Canada	9 063	5 720	3 885	2 798	2 109
Total Canada	90 637	27 202	12 361	7 469	5 299
North Sea	841	707	595	506	436
Other International	1 367	755	452	289	196
Total Probable	92 844	28 664	13 408	8 264	5 930
Proved Plus Probable					
Mining	50 441	22 067	10 870	5 553	2 675
In Situ	84 133	30 036	15 246	9 664	6 953
E&P Canada	10 933	7 255	5 122	3 793	2 913
Total Canada	145 507	59 358	31 238	19 010	12 542
North Sea	1 826	1 641	1 469	1 319	1 193
Other International	1 879	1 049	617	375	233
Total Proved Plus Probable	149 212	62 049	33 323	20 705	13 968

See Note (1) at the end of the Future Net Revenues Tables for important information.

Total Future Net Revenues

as at December 31, 2015
(forecast prices and costs)

(in $ millions, undiscounted)	Revenue	Royalties	Operating Costs	Development Costs	Abandonment and Reclamation Costs	Future Net Revenues Before Deducting Future Income Tax Expenses	Future Income Tax Expenses	Future Net Revenues After Deducting Future Income Tax Expenses
Proved Developed Producing								
Mining	160 045	17 906	79 158	28 675	15 086	19 220	6 358	12 862
In Situ	20 914	754	10 765	2 575	504	6 317	1 336	4 981
E&P Canada	4 531	964	1 603	136	1 046	782	—	782
Total Canada	185 490	19 624	91 525	31 386	16 636	26 318	7 694	18 624
North Sea	4 566	—	1 813	155	637	1 962	1 114	847
Other International	—	—	—	—	—	—	—	—
Total Proved Developed Producing	190 056	19 624	93 339	31 541	17 273	28 280	8 808	19 472
Proved Developed Non-Producing								
Mining	—	—	—	—	—	—	—	—
In Situ(3)	11	(3)	(44)	(3)	2	59	29	30
E&P Canada	8	—	4	1	1	2	—	2
Total Canada	19	(2)	(40)	(2)	2	61	29	32
North Sea	—	—	—	—	—	—	—	—
Other International	8 622	5 962	563	440	434	1 224	783	440
Total Proved Developed Non-Producing	8 641	5 959	523	438	436	1 285	813	472
Proved Undeveloped								
Mining	82 393	9 113	44 132	12 549	1 447	15 152	3 302	11 850
In Situ	117 827	17 650	41 067	25 824	992	32 294	9 016	23 278
E&P Canada	4 805	308	1 251	1 669	475	1 102	16	1 086
Total Canada	205 025	27 071	86 450	40 042	2 914	48 548	12 334	36 214
North Sea	818	—	362	223	16	217	79	138
Other International	5 400	3 970	283	609	318	220	148	72
Total Proved Undeveloped	211 243	31 041	87 095	40 874	3 248	48 985	12 561	36 424
Proved								
Mining	242 438	27 019	123 290	41 224	16 533	34 372	9 660	24 712
In Situ	138 752	18 401	51 788	28 395	1 498	38 670	10 382	28 288
E&P Canada	9 344	1 273	2 858	1 807	1 522	1 885	16	1 870
Total Canada	390 534	46 693	177 935	71 426	19 553	74 927	20 057	54 870
North Sea	5 384	—	2 176	378	652	2 179	1 193	986
Other International	14 022	9 932	846	1 049	752	1 444	931	512
Total Proved	409 940	56 624	180 957	72 853	20 957	78 549	22 182	56 368
Probable								
Mining	129 105	18 104	61 152	13 628	1 932	34 289	8 560	25 728
In Situ	225 831	41 089	69 042	37 675	1 264	76 762	20 917	55 845
E&P Canada	21 910	4 355	3 775	1 042	429	12 308	3 245	9 063
Total Canada	376 846	63 547	133 969	52 345	3 625	123 359	32 723	90 637
North Sea	2 414	—	682	36	37	1 659	818	841
Other International	10 913	6 632	266	127	20	3 869	2 502	1 367
Total Probable	390 172	70 179	134 916	52 508	3 682	128 887	36 043	92 844
Proved Plus Probable								
Mining	371 543	45 123	184 442	54 852	18 465	68 661	18 220	50 441
In Situ	364 583	59 490	120 829	66 070	2 762	115 432	31 299	84 133
E&P Canada	31 254	5 628	6 633	2 849	1 951	14 194	3 261	10 933
Total Canada	767 380	110 240	311 904	123 771	23 178	198 287	52 780	145 507
North Sea	7 798	—	2 858	414	689	3 838	2 011	1 826
Other International	24 935	16 563	1 111	1 176	773	5 312	3 433	1 879
Total Proved Plus Probable	800 113	126 803	315 873	125 361	24 640	207 436	58 224	149 212

See Note (3) at the end of the Future Net Revenues Tables.

Future Net Revenues by Product Type(1)
as at December 31, 2015
(forecast prices and costs)

(before income taxes, discounted at 10% per year)	$ millions	Unit Value $/boe(2)
Proved Developed Producing		
SCO	13 312	7.93
Bitumen	1 401	11.99
Light Crude & Medium Crude Oil(4)	2 700	26.68
Heavy Crude Oil	—	—
Conventional Natural Gas(5)	34	6.39
Total Proved Developed Producing	17 447	9.18
Proved		
SCO	17 909	8.25
Bitumen	6 391	3.78
Light Crude & Medium Crude Oil(4)	3 643	21.35
Heavy Crude Oil	109	3.73
Conventional Natural Gas(5)	36	6.39
Total Proved	28 088	6.90
Proved Plus Probable		
SCO	28 814	7.96
Bitumen	7 142	2.98
Light Crude & Medium Crude Oil(4)	8 953	26.97
Heavy Crude Oil	2 390	23.82
Conventional Natural Gas(5)	51	6.45
Total Proved Plus Probable	47 350	7.34

(1) Figures may not add due to rounding.

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

(3) Proved Developed Non-Producing reserves are calculated as the difference between Total Proved Developed and Proved Developed Producing cases, which may result in negative values due to differences in forecasts and related assumptions between the cases.

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

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

Notes to Future Net Revenues Tables

In Situ Future Net Revenues

Future net revenues for In Situ properties reflect the flexibility of Suncor's operations, which allows production from these properties to be either upgraded to SCO or sold as non-upgraded bitumen. The proportion of upgraded production is based on estimated available upgrading capacity and can vary depending on pricing of the respective products, maintenance, fluctuations in production from mining and extraction operations, or changes in the company's overall Oil Sands development strategy.

Future net revenues disclosed above include the estimated future sales prices, and associated upgrader operating and sustaining capital costs, assuming that approximately 50-57% of Firebag bitumen production is upgraded to SCO from 2016 to 2033 and 100% thereafter (for total proved plus probable reserves). These assumptions have resulted in a $2.7 billion increase in the net present value of future net revenues (total proved plus probable reserves, before tax, discounted at 10%) attributable to In Situ production relative to the scenario where none of the bitumen is upgraded.

Revenues and the natural gas fuel expense associated with excess power generated from cogeneration facilities at Firebag are included in future net revenues.

Forecast Prices and Costs

Crude oil, natural gas and other important benchmark reference pricing, as well as inflation and exchange rates utilized in the GLJ Reports and the Sproule Reports, were derived using averages of forecasts developed by GLJ, Sproule and McDaniel & Associates Consultants Ltd. dated January 1, 2016. Resultant forecasts are set out below. To the extent that there are fixed or presently determinable future prices or costs to which Suncor is legally bound by contractual or other obligations to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs have been incorporated into the forecast prices as applied to the pertinent properties. The forecast cost and price assumptions include increases in wellhead selling prices, take into account inflation with respect to future operating and capital costs, and assume the continuance of current laws and regulations. The inflation rates utilized in the forecasts were 0.7% in 2016, 1.3% in 2017 and 1.8% in 2018 and thereafter.

Prices Impacting Reserves Tables[1]

Forecast	Brent North Sea[2]	WTI Cushing Oklahoma	WCS Hardisty Alberta[3]	Light Sweet Edmonton Alberta[4]	Pentanes Plus Edmonton Alberta[5]	AECO Gas[6]	B.C. Gas Westcoast Station 2[7]	National Balancing Point North Sea[8]
Year	US$/bbl	US$/bbl	Cdn$/bbl	Cdn$/bbl	Cdn$/bbl	Cdn$/mmbtu	Cdn$/mmbtu	Cdn$/mmbtu
2016	45.83	44.67	44.64	55.89	60.16	2.57	1.91	7.45
2017	56.73	55.20	54.52	66.47	70.95	3.14	2.70	7.98
2018	65.33	63.47	60.32	73.21	78.05	3.47	3.14	8.28
2019	72.90	71.00	67.42	81.35	86.58	3.80	3.51	8.98
2020	76.67	74.77	70.47	84.57	90.00	3.99	3.70	9.25
2021	80.17	78.24	73.50	87.88	93.46	4.13	3.84	9.53
2022	83.68	81.75	77.25	92.01	97.79	4.30	3.98	9.91
2023	87.34	85.37	80.95	96.24	102.23	4.48	4.16	10.29
2024	89.46	87.32	83.09	98.17	104.29	4.60	4.28	10.57
2025	91.10	88.90	84.56	99.94	106.16	4.70	4.38	10.76
2026	92.76	90.54	86.15	101.79	108.13	4.79	4.47	10.95
2027	94.50	92.22	87.76	103.69	110.14	4.88	4.55	11.14
2028	96.23	93.90	89.33	105.55	112.12	4.96	4.64	11.34
2029	97.98	95.62	90.97	107.49	114.18	5.05	4.72	11.54
2030	99.82	97.40	92.67	109.49	116.31	5.15	4.81	11.74
2031+	1.8%/yr	1.8%/yr	1.8%/yr	1.8%/yr	1.8%/yr	1.8%/yr	1.8%/yr	1.8%/yr

(1) Benchmark forecast prices have been adjusted for quality differentials and transportation costs applicable to the specific evaluation areas and products.
(2) Price used when determining offshore light crude and medium crude oil and heavy crude oil reserves for E&P Canada, North Sea reserves and Other International reserves.
(3) Price used when determining bitumen reserves presented as In Situ and Mining reserves as well as for determining bitumen pricing for royalty calculation purposes.
(4) Price used when determining SCO reserves presented as In Situ and Mining reserves.
(5) Price used when determining the cost of diluent associated with bitumen reserves presented as In Situ and Mining reserves, as well as when accounting for diluent in determining bitumen pricing for royalty calculation purposes. A bitumen/diluent ratio of approximately two barrels of bitumen for one barrel of diluent was used. Price also used when determining NGLs reserves.
(6) Price used when determining natural gas input costs for the production of SCO and bitumen reserves.
(7) Price used when determining conventional natural gas reserves for E&P Canada areas.
(8) Price used when determining conventional natural gas reserves presented as North Sea reserves.

Foreign Exchange Rates Impacting Forecast Prices

Forecast	US$/Cdn$ Exchange Rate	Cdn$/€ Exchange Rate	Cdn$/£ Exchange Rate
Year			
2016	0.735	1.497	2.041
2017	0.767	1.435	2.022
2018	0.802	1.372	1.933
2019	0.817	1.347	1.898
2020	0.833	1.320	1.860
2021+	0.842	1.307	1.842

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

Values presented in the table for Net Present Value of Future Net Revenues After Income Taxes reflect income tax burdens of assets at an individual asset level (for In Situ) or at a business area or legal entity level (for Mining, North Sea and E&P Canada) based on tax pools associated with that business area or legal entity. Income taxes for Other International assets are determined by their respective EPSAs. Suncor's actual corporate legal entity structure for income taxes and income tax planning has not been considered, and, therefore, the total value for income taxes presented in the total future net revenues table may not provide an estimate of the value at the corporate entity level, which may be significantly different. The 2015 audited Consolidated Financial Statements and the MD&A should be consulted for information on income taxes at the corporate entity level.

Additional Information Relating to Reserves Data

Future Development Costs[1]

as at December 31, 2015
(forecast prices and costs)

($ millions)	2016	2017	2018	2019	2020	Remainder	Total	Discounted At 10%
Proved								
Mining	3 906	3 521	2 422	2 110	2 472	26 793	41 224	20 074
In Situ	812	780	1 196	1 879	679	23 051	28 395	10 618
E&P Canada	696	370	41	94	94	512	1 807	1 392
Total Canada	5 414	4 670	3 658	4 082	3 245	50 356	71 426	32 085
North Sea	156	116	11	9	13	72	378	307
Other International	18	91	97	152	122	570	1 049	551
Total Proved	5 588	4 877	3 766	4 243	3 380	50 998	72 853	32 943
Proved Plus Probable								
Mining	3 920	3 536	2 466	2 166	2 594	40 170	54 852	21 865
In Situ	796	826	850	1 379	894	61 325	66 070	11 617
E&P Canada	853	540	144	215	295	802	2 849	2 111
Total Canada	5 569	4 902	3 459	3 760	3 784	102 298	123 771	35 594
North Sea	156	116	11	9	13	108	414	318
Other International	18	103	98	156	125	676	1 176	587
Total Proved Plus Probable	5 743	5 121	3 568	3 925	3 921	103 082	125 361	36 499

(1) Figures may not add due to rounding.

Development costs include costs associated with both developed and undeveloped reserves. Significant development activities and costs for 2016 are expected to include:

- Development activities for Fort Hills continue to focus on procurement and field construction activities. For Mining, turnaround and major maintenance at Upgrader 2, development of fluid management facilities for Oil Sands Base, and utilities sustainment, mining and tailings projects at Syncrude. Remaining development costs for Oil Sands Base and Syncrude relate to capital investments that maintain the production capacity of existing facilities, including, but not limited to, major maintenance, truck and shovel replacement, the replenishment of catalysts in hydrotreating units at the upgraders and improvements to utilities, roads and other facilities.
- For both Firebag and MacKay River operations within In Situ, the drilling of new well pairs as well as the design and construction of new well pads that are expected to maintain existing production levels in future years.
- For E&P Canada, construction activities at Hebron, as well as development drilling at Hibernia, the HSEU and White Rose.
- For North Sea, continuation of Golden Eagle development drilling.

Management currently believes that internally generated cash flows, existing and future credit facilities, and access to debt capital markets are sufficient to fund future development costs. There can be no guarantee that funds will be available or that Suncor will allocate funding to develop all of the reserves attributed in the GLJ Reports and the Sproule Reports. Failure to develop those reserves would have a negative impact on future cash flow from operating activities.

Interest expense or other costs of external funding are not included in the reserves and future net revenues estimates and could reduce future net revenues to some degree depending upon the funding sources utilized. Suncor does not anticipate that interest expense or other funding costs on their own would make development of any property uneconomic.

Abandonment and Reclamation Costs

The company completes an annual review of its consolidated abandonment and reclamation cost estimates. The estimates are based on the anticipated method and extent of restoration, consistent with legal requirements, technological advances and the possible future use of the site.

As at December 31, 2015, Suncor estimated its undiscounted, uninflated abandonment and reclamation costs for its upstream assets to be approximately $9.7 billion (discounted at 10%, approximately $3.0 billion). Abandonment and reclamation costs are limited to current disturbances at December 31, 2015, and exclude estimated abandonment and reclamation costs for its Refining and Marketing assets ($0.2 billion, undiscounted and uninflated). Suncor estimates that it will incur $1.3 billion of its identified abandonment and reclamation costs during the next three years (undiscounted: 2016 – $0.4 billion, 2017 – $0.4 billion, 2018 – $0.5 billion), more than 80% of which is associated with Oil Sands mining operations.

Approximately $24.6 billion (inflated and undiscounted) has been deducted as abandonment and reclamation costs in estimating the future net revenues from proved plus probable reserves, including $21.2 billion related to the company's oil sands upgraders, extraction facilities, tailings ponds, sub-surface wells and central processing facilities, which includes amounts related to current disturbances.

As a result of regulatory changes to reserves reporting requirements, the abandonment and reclamation cost estimate included in the net present values of the company's proved and probable reserves now include costs related to the reclamation of disturbed land from oil sands mining activities, future mining disturbances, the treatment of legacy oil sands tailings, the decommissioning of oil sands and natural gas processing facilities and well pads, existing and future reserves wells and associated service wells, disturbed lease sites, and future lease site disturbances. Historically, the abandonment and reclamation cost estimates included in the net present values of proved and probable reserves were limited to the abandonment of production and service wells, including forecasted wells for undeveloped reserves.

Gross Proved and Probable Undeveloped Reserves
The tables below outline the gross proved and probable undeveloped reserves and represent undeveloped reserves additions resulting from acquisitions, discoveries, infill drilling, improved recovery and/or extensions in the year when the events first occurred.

Gross Proved Undeveloped Reserves[1]
(forecast prices and costs)

	2013		2014		2015	
	First Attributed	Total at December 31 2013	First Attributed	Total at December 31 2014	**First Attributed**	**Total at December 31 2015**
SCO (mmbbls)						
Mining	—	—	—	—	—	—
In Situ	75	564	—	532	—	**584**
Total SCO	75	564	—	532	—	**584**
Bitumen (mmbbls)						
Mining	845	845	—	845	**207**	**1 052**
In Situ	74	875	—	830	—	**741**
Total Bitumen	918	1 720	—	1 674	**207**	**1 792**
Light Crude & Medium Crude Oil (mmbbls)						
E&P Canada[2]	2	27	38	52	—	**22**
North Sea	—	25	—	16	—	**10**
Other International[3]	—	5	—	2	—	**51**
Total Light Crude & Medium Crude Oil	2	57	38	70	—	**82**
Heavy Crude Oil (mmbbls)						
E&P Canada[2]	—	—	—	—	—	**30**
North Sea	—	—	—	—	—	—
Other International[3]	—	—	—	—	—	—
Total Heavy Crude Oil	—	—	—	—	—	**30**
Natural Gas (bcfe)[4]						
E&P Canada[2]	4	5	—	—	—	—
North Sea	—	1	—	1	—	**1**
Other International[3]	—	—	—	—	—	—
Total Natural Gas	4	6	—	1	—	**1**
Total (mmboe)	996	2 342	38	2 277	**207**	**2 488**

Gross Probable Undeveloped Reserves[1]
(forecast prices and costs)

	2013		2014		2015	
	First Attributed	Total at December 31 2013	First Attributed	Total at December 31 2014	**First Attributed**	**Total at December 31 2015**
SCO (mmbbls)						
Mining	—	265	—	265	—	**265**
In Situ	—	1 074	—	1 112	—	**1 207**
Total SCO	—	1 339	—	1 378	—	**1 473**
Bitumen (mmbbls)						
Mining	397	397	—	408	**107**	**542**
In Situ	—	369	—	268	—	**250**
Total Bitumen	397	766	—	677	**107**	**791**
Light Crude & Medium Crude Oil (mmbbls)						
E&P Canada[2]	22	236	10	189	**5**	**88**
North Sea	—	23	—	13	—	**4**
Other International[3]	—	9	1	3	—	**42**
Total Light Crude & Medium Crude Oil	22	267	11	205	**5**	**133**
Heavy Crude Oil (mmbbls)						
E&P Canada[2]	—	—	—	—	—	**82**
North Sea	—	—	—	—	—	**—**
Other International[3]	—	—	—	—	—	**—**
Total Heavy Crude Oil	—	—	—	—	—	**82**
Natural Gas (bcfe)[4]						
E&P Canada[2]	17	21	—	3	—	**3**
North Sea	—	2	—	1	—	**1**
Other International[3]	—	—	—	—	—	**—**
Total Natural Gas	17	23	—	4	—	**3**
Total (mmboe)	422	2 376	11	2 260	**112**	**2 479**

(1) Figures above may not add due to rounding.
(2) E&P Canada includes properties previously held by Suncor and subsequently disposed of in 2013 and 2014.
(3) Other International includes certain volumes for Libya that have been reclassified to undeveloped due to facility damage.
(4) All conventional natural gas, other than immaterial amounts of NGLs (less than 0.6 mmbbls).

Undeveloped In Situ reserves, which constitute approximately 53% of Suncor's gross proved undeveloped reserves and 59% of Suncor's gross probable undeveloped reserves have been assigned to reserves areas which are not classified as developed producing. Where supported by core hole wells, proved undeveloped reserves have been attributed to regions within 1.2 km from currently drilled or near-term planned production wells where AER approval is pending and, in the case of Firebag, also within 2.4 km from producing wells. Suncor has delineated In Situ reserves to a high degree of certainty through seismic data and core hole drilling, consistent with COGE Handbook guidelines. In most cases, proved reserves have been drilled to a density of 16 wells per section, which is in excess of the eight wells per section required for regulatory approval. Further delineation is pursued through annual core hole drilling programs. Management uses integrated plans to forecast future development. These detailed plans align current production, processing and pipeline constraints (which, in the case of processing constraints, do not permit Suncor to develop all of its undeveloped In Situ reserves within two years), capital spending commitments and future development for the next ten years, and are reviewed and updated annually for internal and external factors affecting planned activity. The timing associated with developing undeveloped In Situ reserves is a function of the forecasts of the declining production from existing In Situ wells, and will take several years to develop, depending on performance. When existing wells decline, Suncor commences development of the reserves and wells surrounding the declining areas. This will entail drilling replacement well pairs and constructing sustaining pads. The economic viability of developing the sustaining pads and associated well pairs is tested to ensure that ongoing development is economic as required for reserves assessment. Sustaining pads are at various stages of development, from pad regulatory approval awaiting final internal approval to pad regulatory application to more detailed continuing core hole evaluation. Final internal approvals are aligned with declining production from the existing In Situ wells.

Undeveloped Mining reserves constitute approximately 42% of Suncor's gross proved undeveloped reserves and 32% of Suncor's gross probable undeveloped reserves, and relate to the Fort Hills mining project and Syncrude Aurora South mining area, which have regulatory approvals substantially in place and are well-delineated by core hole drilling. Suncor is currently completing construction of the Fort Hills mining area, and first oil is expected by the fourth quarter of 2017. The co-owners of Syncrude do not expect that the Aurora South mining area will come on-stream before 2023, when production from the Mildred Lake mining area is expected to be complete.

Undeveloped conventional reserves (light crude oil and medium crude oil, heavy crude oil, and natural gas) constitute approximately 5% of Suncor's gross proved undeveloped reserves and approximately 9% of Suncor's gross probable undeveloped reserves. Undeveloped conventional reserves primarily relate to the company's offshore assets at E&P Canada, mainly associated with Hebron which is currently under development (first oil expected in 2017), and under-drilled or undrilled fault blocks related to extension areas in Hibernia, White Rose and Terra Nova. In 2015, extensive damage was sustained in Libya to the facilities associated with EPSA 5. As a result, Suncor has reclassified the associated reserves for EPSA 5 from developed non-producing to undeveloped. In developing undeveloped conventional reserves, Suncor considers existing facility capacity, capital allocation plans, and remaining reserve availability. Accordingly, in some cases, it will take longer than two years to develop all of the currently assigned undeveloped conventional reserves. Suncor plans to develop the majority of the conventional proved undeveloped reserves over the next five years and the majority of the conventional probable undeveloped reserves over the next seven years.

Properties with no Attributed Reserves

The following table is a summary of properties to which no reserves are attributed as at December 31, 2015. For lands in which Suncor holds interests in different formations under the same surface area pursuant to separate leases, the area has been counted for each lease.

Country	Gross Hectares	Net Hectares
Canada	6 581 794	3 755 580
Libya	2 950 978	1 339 489
U.S. – Alaska	481 740	160 564
Syria	345 194	345 194
Norway	286 775	76 775
U.K.	119 541	35 599
Australia (overriding royalty interest only)	113 027	—
Total	10 879 049	5 713 201

Suncor's undeveloped petroleum assets include exploration properties in a preliminary phase of evaluation, to discovery areas where tenure to the property is held indefinitely on the basis of hydrocarbon test results, but where economic development is not currently possible or has not yet been sanctioned. Certain Mining and In Situ properties may be in a relatively mature phase of evaluation, where a significant amount of development has occurred; however, reserves cannot be attributed due to one or more contingencies, such as project sanction. In many cases where reserves are not attributed to lands containing one or more discovery wells, the key limiting factor is the lack of available production infrastructure. Each year, as part of the company's process to review the economic viability of its properties, some properties are selected for further development activities, while others are temporarily deferred, sold, swapped or relinquished back to the mineral rights owner.

In 2016, Suncor's rights to 48,392 net hectares in Canada, 37,325 net hectares in Norway and 17,094 net hectares in the U.K. are scheduled to expire. The expiries include approximately 2,800 net hectares in In Situ and 2,200 net hectares in Mining. Substantial portions of expiring lands may have their tenure continued beyond 2016 through the conduct of work programs and/or the payment of prescribed fees to the rights owner.

Oil and Gas Properties and Wells(1)

The following table is a summary of oil and gas wells as at December 31, 2015.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing(2)(3)		Producing		Non-Producing(2)(3)	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta – In Situ(4)	286.0	286.0	322.0	262.3	—	—	—	—
British Columbia	—	—	—	—	28.0	26.5	21.0	16.9
Newfoundland	66.0	16.6	5.0	1.8	—	—	—	—
North Sea	37.0	10.8	7.0	2.0	—	—	—	—
Other International(5)	—	—	419.0	211.1	—	—	6.0	6.0
Total	389.0	313.4	753.0	477.2	28.0	26.5	27.0	22.9

(1) All oil and gas wells are onshore, other than Newfoundland and the North Sea.

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

(3) Non-producing wells do not necessarily lead to classification of non-producing reserves.

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

(5) Other International includes wells associated with the company's suspended operations in Syria and Libya.

There are no producing wells associated with Mining properties. Suncor has no proved developed non-producing reserves or probable developed non-producing reserves in its Mining reserves.

For In Situ properties, proved non-producing reserves and probable non-producing reserves are associated with wells that have been drilled within the last three years, which require further capital for completion and tie-in to facilities to bring the wells on-stream. Because this capital is small relative to the cost to drill, complete and tie-in a well pair, the associated reserves are considered developed.

For Other International, non-producing reserves are associated with wells in Libya that were suspended in the fourth quarter of 2015, due to political unrest in the country, which resulted in the closure of export terminal operations. Production in Libya remains impacted by political unrest, with the timing of a return to normal operations remaining uncertain. As such, all reserves associated with EPSAs 1-4 have been classified as non-producing, while reserves associated with EPSA 5, where facilities have been damaged, have been classified as undeveloped in light of the costs required to repair facilities and restore production.

Costs Incurred

The table below summarizes the company's costs incurred related to its oil and gas activities for the year ended December 31, 2015.

($ millions)	Exploration Costs	Proved Property Acquisition Costs	Unproved Property Acquisition Costs	Development Costs	Total
Canada – Mining and In Situ	157	360	18	3 553	4 088
Canada – E&P Canada	131	—	1	869	1 001
Total Canada	288	360	19	4 422	5 089
North Sea	252	—	—	164	416
Other International	12	—	—	—	12
Total	552	360	19	4 586	5 517

Exploration and Development Activities

The table below outlines the gross and net exploratory and development wells the company completed during the year ended December 31, 2015.

	Exploratory Wells(1)		Development Wells	
Total number of wells completed	Gross	Net	Gross	Net
Canada – Oil Sands				
Oil	—	—	24	24
Service(2)	—	—	29	29
Stratigraphic Test(3)	386.0	241.3	151	61
Total	386.0	241.3	204	114
Canada – E&P Canada				
Oil	—	—	3	0.7
Dry Hole	1	0.4	1	0.2
Natural Gas	—	—	—	—
Service(2)	—	—	1	0.2
Stratigraphic Test(3)	—	—	—	—
Total	1	0.4	5	1.1
North Sea				
Oil	—	—	7	1.9
Service(2)	—	—	4	1.1
Dry Hole	4	2.5	—	—
Stratigraphic Test(3)	—	—	—	—
Total	4	2.5	11	3.0

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

(2) Service wells for Oil Sands include the injection well in a SAGD well pair, in addition to observation and disposal wells. Service wells for E&P Canada include water and gas injection wells. Service wells for North Sea include water injection wells.

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

Significant exploration and development activities in 2015 included:

- For Mining, stratigraphic test well drilling programs and other survey work at Oil Sands Base and Syncrude to provide additional information on areas the company expects to mine in the near term.
- For In Situ, the drilling of new well pairs and infill wells at Firebag and MacKay River that are expected to assist in maintaining production levels in future years, stratigraphic test well drilling programs at MacKay River, Meadow Creek, Firebag and Lewis to further delineate resources, and activity to start up pilot technology projects.
- For E&P Canada, construction activities at Hebron, development drilling for Hibernia, the HSEU, White Rose and the South White Rose Extension. E&P Canada also included exploration drilling in the Shelburne Basin.
- For North Sea, continuation of development drilling for Golden Eagle, and exploration drilling in Norway and U.K. sectors of North Sea.

For significant exploration and development activities expected to occur in 2016 and beyond, see Narrative Description of Suncor's Businesses and Future Development Costs herein.

Production History(1)

2015	Q1	Q2	Q3	Q4	Year Ended
Canada – Oil Sands(2)					
Total production (mbbls/d)	475.6	448.7	458.4	470.6	463.4
SCO (mbbls/d)	381.7	352.3	343.0	323.1	349.9
Non-upgraded bitumen (mbbls/d)	93.9	96.4	115.4	147.5	113.5
($/bbl)					
Average price realized	48.30	61.63	48.85	42.55	50.26
Royalties	(0.44)	(0.93)	(1.14)	(0.22)	(0.67)
Total cash operating costs(3)	(28.95)	(29.57)	(27.89)	(28.82)	(28.80)
Canada – Light Crude & Medium Crude Oil(4)					
Total production (mbbls/d)	58.1	37.0	36.9	43.5	43.8
($/bbl)					
Average price realized(5)	66.38	78.23	59.09	52.51	65.12
Royalties	(17.58)	(16.38)	(4.39)	(5.79)	(12.49)
Production costs	(11.33)	(18.36)	(20.63)	(19.67)	(16.33)
Netback	37.47	43.49	34.07	27.05	36.30
North Sea – Light Crude & Medium Crude Oil(6)					
Total production (mboe/d)	61.2	66.9	67.0	63.2	64.6
($/boe)					
Average price realized(5)	64.48	72.84	62.86	54.91	63.85
Royalties	—	—	—	—	—
Production costs	(9.65)	(8.52)	(8.42)	(8.42)	(8.70)
Netback	54.83	64.32	54.44	46.49	55.15

(1) Production and liftings in Libya have been intermittent and are not considered material to Suncor and therefore are not included.

(2) Suncor measures cash operating cost on a production volumes basis for its Oil Sands operations. For this reason, a netback calculation for SCO and bitumen is not presented. Amounts presented include results from the company's share of Syncrude.

(3) Non-GAAP financial measures. See the Advisories section of this AIF.

(4) Volumes exclude natural gas and NGLs production from E&P Canada onshore properties, which is not considered material to Suncor.

(5) Average price realized is net of transportation costs, but before royalties.

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

The following table provides the production volumes on a working-interest basis, before royalties for each of Suncor's significant fields for the year ended December 31, 2015.

	SCO	Bitumen	Light & Medium Oil
	mbbls/d	mbbls/d	mbbls/d
Mining – Suncor	239.0	—	—
Mining – Syncrude	30.0	—	—
Firebag	80.3	83.6	—
MacKay River	0.7	29.8	—
Buzzard	—	—	49.8
GEAD	—	—	14.8
Hibernia	—	—	18.1
White Rose	—	—	12.2
Terra Nova	—	—	13.5
Total	350.0	113.4	108.4

Production Estimates

The table below outlines the production estimates for 2016 that are included in the estimates of gross proved reserves and gross probable reserves as at December 31, 2015. Total Proved plus Probable production estimates from Suncor's mining operations (excluding Syncrude) are 222.3 mbbls/d of SCO, approximately 39% of total estimated production for 2016, and from Firebag are 165.0 mbbls/d of SCO and bitumen, approximately 29% of total estimated production for 2016.

	SCO (mbbls/d)		Bitumen (mbbls/d)		Light & Medium Oil (mbbls/d)		Natural Gas (mmcfe/d)[(1)]		Total (mmboe/d)	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Canada										
Proved	319	314	106	105	42	34	13	12	469	455
Probable	21	21	8	8	9	8	1	1	38	37
Proved Plus Probable	340	335	114	112	51	42	14	13	507	492
North Sea										
Proved	—	—	—	—	46	46	5	5	47	47
Probable	—	—	—	—	4	4	1	1	4	4
Proved Plus Probable	—	—	—	—	50	50	5	5	51	51
Other International										
Proved	—	—	—	—	9	2	—	—	9	2
Probable	—	—	—	—	—	—	—	—	—	—
Proved Plus Probable	—	—	—	—	9	2	—	—	9	2
Total										
Proved	319	314	106	105	96	82	18	16	524	504
Probable	21	21	8	8	13	12	2	2	42	41
Proved Plus Probable	340	335	114	112	109	94	20	18	566	545

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

Work Commitments

The practice of governments requiring companies to pledge to carry out work commitments in exchange for the right to carry out exploration for and development of hydrocarbons is common, particularly in unexplored or lightly explored regions of the world. The following table shows the estimated values of work commitments Suncor has made in regard to the lands it holds as at December 31, 2015. These commitments run through 2021 and beyond, and are primarily for conducting seismic programs and drilling exploration wells.

Country/Area ($ millions)	2016	Total
Canada	—	96
North Sea	1	1
Other International	—	497

Forward Contracts

Suncor may use financial derivatives to manage its exposure to fluctuations in commodity prices; however, Suncor did not consider any financial derivative transactions to be material in 2015. A description of Suncor's use of such instruments is provided in the 2015 audited Consolidated Financial Statements and related MD&A for the year ended December 31, 2015.

Tax Horizon

In 2015, Suncor was subject to cash tax in the majority of the jurisdictions in which it generates earnings, including earnings related to its Canadian, North Sea and Other International production.

INDUSTRY CONDITIONS

The oil and natural gas industry is subject to extensive controls and regulations governing its operations (including land tenure, exploration, environmental, development, production, refining, transportation and marketing). These regulations are imposed by legislation enacted by various levels of government, and, with respect to export and taxation of oil and natural gas, by agreements among the governments of Canada, Ontario, Quebec, Alberta, British Columbia, and Newfoundland and Labrador, as well as the governments of the United States and other foreign jurisdictions in which we operate, all of which should be carefully considered by investors in the oil and gas industry. All current legislation is a matter of public record. All governments have the ability to change legislation; the company is unable to predict what additional legislation or amendments may be enacted. Suncor may engage in the discussion on proposed changes to ensure Suncor's interests are recognized. The following discussion outlines some of the principal aspects of legislation, regulations and agreements governing Suncor's operations.

Pricing, Marketing and Exporting Crude Oil

The producers of oil are entitled to negotiate sales and purchase agreements directly with oil purchasers. Most agreements are linked to global oil prices. In Canada, oil exporters are also entitled to enter into export contracts. If the term of an export contract exceeds one year for light and medium crude oil or exceeds two years for heavy crude oil (to a maximum of 25 years), the exporter is required to obtain an export licence from the National Energy Board (NEB). If the term of an export contract does not exceed one year for light and medium crude oil or does not exceed two years for heavy crude oil, the exporter is required to obtain an order approving such export from the NEB. The NEB is currently drafting amending regulations to update the current regulations governing the issuance of export licences. The updating process is necessary to meet the criteria set out in the federal *Jobs, Growth and Long-Term Prosperity Act*, which received Royal Assent on June 29, 2012 (the Prosperity Act). In the transitory period, the NEB has issued, and is currently following, an Interim Memorandum of Guidance concerning *Oil and Gas Export Applications and Gas Import Applications under Part VI of the National Energy Board Act*.

Under the North American Free Trade Agreement (NAFTA), Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not (i) reduce the proportion of energy resources exported relative to the total supply of goods of the party maintaining the restriction as compared to the proportion prevailing in the most recent 36-month period; (ii) impose an export price higher than the domestic price (subject to an exception with respect to certain measures which only restrict the volume of exports); and (iii) disrupt normal channels of supply. All three countries are prohibited from imposing minimum or maximum export or import price requirements.

NAFTA requires energy regulators to ensure the orderly and equitable implementation of any regulatory changes and to ensure that the application of those changes will cause minimal disruption to contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements, all of which are important for Canadian oil and natural gas exports.

Internationally, prices for crude oil and natural gas fluctuate in response to changes in the supply of and demand for crude oil and natural gas, market uncertainty and a variety of other factors beyond Suncor's control. These factors include, but are not limited to, the actions of OPEC, world economic conditions, government regulation, political developments, the foreign supply of oil, the price of foreign imports, the availability of alternate fuel sources, and weather conditions.

Royalties, Incentives and Income Taxes

Canada

The royalty regime is a significant factor in the profitability of SCO, bitumen, crude oil, NGLs and natural gas production. Royalties on production from lands other than Crown lands are determined by negotiations between the mineral freehold owner and the lessee, although production from such lands may be subject to certain provincial taxes. Crown royalties are determined by governmental regulation or by agreement with government in certain circumstances, which are subject to change as a result of numerous factors, including political considerations, and are generally calculated as a percentage of revenues received from the value of the gross production. The royalty rate generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery, depth of well, and the type or quality of the petroleum product produced. Other royalties and royalty-like interests are, from time to time, carved out of the owner's working interest through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests or net carried interests.

For a discussion of the royalties in Alberta and Newfoundland and Labrador, refer to the Narrative Description of Suncor's Businesses section of this AIF.

The Canadian federal corporate income tax rate levied on taxable income was 15% for active business income, including resource income. The average provincial income tax rate for Suncor in 2015 was 11.34%. In the second quarter of 2015, the Government of Alberta enacted an increase in the corporate income tax rate from 10% to 12% effective July 1, 2015, which changed the combined federal and provincial income tax rate from 25.66% to 26.34%.

Other Jurisdictions

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

Operations in the U.K. are subject to a tax rate of 50%, made up of the corporate income tax rate and the supplemental charge. Suncor earns refundable tax credits related to eligible exploration spending in Norway at a rate of 78%.

Amounts presented in Suncor's 2015 audited Consolidated Financial Statements as royalties for production from the company's Libya operations are determined pursuant to EPSAs. The amounts calculated reflect the difference between Suncor's working interest in the particular project and the net revenue attributable to Suncor under the terms of the respective EPSAs. All government interests in these operations, except for income taxes, are presented as royalties.

Land Tenure

In Canada, crude oil and natural gas located in the western provinces are owned predominantly by the respective provincial governments. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences and permits for varying terms, and on conditions set forth in provincial legislation, including requirements to perform specific work or make payments. Oil and natural gas located in such provinces can also be privately owned, and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as negotiated. In frontier areas of Canada, the mineral rights are primarily owned by the Canadian federal government, which, either directly or through shared jurisdiction agreements with the relevant provincial authorities, grants tenure in the form of exploration, significant discovery and production licences.

In many other international jurisdictions, crude oil and natural gas are most commonly owned by national governments that grant rights in the form of exploration licences and permits, production licences, PSCs and other similar forms of tenure. In all cases, Suncor's right to explore, develop and produce crude oil and natural gas is subject to ongoing compliance with the regulatory requirements established by the relevant country.

Environmental Regulation

The company is subject to environmental regulation under a variety of Canadian, U.S., U.K. and other foreign, federal, provincial, territorial, state and municipal laws and regulations. These regulatory regimes are laws of general application. Among other things, they provide for restrictions and prohibitions on the spill, release or emission of various substances produced in association with production that apply to Suncor and other companies in the energy industry. The regulatory regimes require Suncor to obtain operating licences and permits in order to operate, and impose certain standards and controls on activities relating to mining, oil and gas exploration, development and production, and the refining, distribution and marketing of petroleum products and petrochemicals. Environmental assessments and regulatory approvals are generally required before initiating most new major projects or undertaking significant changes to existing operations. In addition, this legislation requires that the company abandon and reclaim mine, well and facility sites to the satisfaction of regulatory authorities and, in some cases, this burden may remain with the company even after disposition of an asset to a third party. Compliance with such legislation can require significant expenditures, and a breach of these requirements may result in suspension or revocation of necessary licences and authorizations, civil liability for pollution damage, and the imposition of material fines and penalties. In addition to these specific, known requirements, Suncor expects future changes to environmental legislation, including anticipated legislation for air pollution (Criteria Air Contaminants) and GHG emissions that will impose further requirements on companies operating in the energy industry.

A number of statutes, regulations and frameworks are under development or have been issued by various provincial regulators that oversee oil sands development, including the Joint Canada-Alberta Implementation Plan for Oil Sands Monitoring, and the Lower Athabasca Regional Plan (LARP) that implements a land-use regime in the Athabasca oil sands. These statutes, regulations and frameworks relate to such issues as tailings management, water use, air emissions and land use. While the financial implications of statutes, regulations and frameworks under development are not yet known, the company is committed to working with the appropriate regulatory bodies as they develop new policies, and to fully complying with all existing and new statutes, regulations and frameworks as they apply to the company's operations.

In general, there remains uncertainty around the outcomes and impacts of climate change and environmental laws and regulations, whether currently in force or enacted in the future. It is not currently possible to predict the nature of any future requirements or the impact on the company and its business, financial condition, results of operations and cash flow. We continue to actively work to mitigate our environmental impact, including taking action to reduce GHG emissions, investing in renewable forms of energy such as wind power and biofuels, continuing land reclamation activities, installing new emissions abatement equipment, investing in research and development, and working to advance other environmental technologies such as solvent-based extraction techniques.

Recent environmental regulation and initiatives have had an impact on many areas important to Suncor's operations, some of which are summarized in the following subsections.

Climate Change

Suncor operates in many jurisdictions that have regulated, or have proposed to regulate, industrial GHG emissions. Regulated jurisdictions generally have policies based on (i) caps on the intensity of GHG emissions including absolute GHG emissions limits, (ii) a cap-and-trade system, (iii) a carbon price, (iv) a hybrid of a carbon price and a cap-and-trade system, or (v) complementary policies such as low carbon fuel and renewable fuel standards. Suncor is committed to fully complying with existing regulations and will continue to constructively engage the appropriate governmental bodies in meaningful dialogue to harmonize regulations across jurisdictions within North America, which focus on achieving actual reduction goals and sustainable resource development.

<u>International Climate Change Agreements and Treaties</u>

A new high level global climate agreement with a goal to limit warming to less than 2C above pre-industrial levels was reached during the United Nations Framework Convention on Climate Change Conference of the Parties held in Paris. The agreement requires ratification by at least 55 parties representing an estimated 55% of total global GHG emissions before taking effect in 2020. The Government of Canada submitted its post-2020 intended nationally determined contribution (INDC) to reduce GHG emissions economy-wide by 30% below 2005 levels by 2030. In comparison, the U.S. INDC is to reduce GHGs by 26-28% to 2005 levels by 2025. G7 leaders also announced a GHG reduction target of 40-70% reductions by 2050 compared to 2010 levels. The G7 emphasized their commitment to "the long-term objective of applying effective policies and actions throughout the global economy, including carbon market-based and regulatory instruments".

<u>Canadian Federal GHG Regulations</u>

The current federal government plans to establish a national climate change framework to reduce emissions supported by provincial government action and co-operation. In addition, the Government of Canada continues to pursue harmonization with the U.S. (where appropriate). Examples include regulations around natural gas electricity generation and methane reduction from natural gas and other petroleum systems. In line with the U.S., Canada has acted upon the phase-out of thermal electricity from coal. It has adopted a renewable fuels standard, mandating that 5% of gasoline supply come from renewable sources such as ethanol and that 2% of diesel supply come from bio-diesel.

<u>Canadian Provincial GHG Regulations</u>

At the 2015 Canadian Premiers' conference, the leaders of all 10 provinces and three territories worked towards their vision and principles for a Canadian Energy Strategy (CES) that enhances actions on clean energy and climate change in Canada. The CES focuses on subnational co-operative climate change mitigation action, and highlights carbon pricing and carbon capture and storage to ensure a secure energy future that promotes economic growth while ensuring a high standard of environmental and social responsibility. In addition, various Canadian provinces have advanced their own GHG emissions reduction targets and passed legislation to regulate emitters.

The Government of Alberta released its Climate Leadership Plan framework for a climate change regulation that applies a $30/ton carbon price on all emissions at an economy-wide level starting in 2018 with the flexibility to adjust prices over time. In order to address competitiveness concerns of trade-exposed sectors like the oil sands, facilities will pay the carbon price above a yet-to-be established performance benchmark for each of in situ, mining, upgrading and refining. In addition, a legislated emissions limit of 100 megatons per year in the oil sands sector with provisions for cogeneration and new upgrading facilities will be introduced allowing for continued growth and development while accelerating emissions reduction technology and operational optimization. The current *Specified Gas Emitters Regulation* (SGER) enacted under the *Climate Change and Emissions Management Act (Alberta)*, will continue, with the emissions intensity requirement of a regulated facility increasing to a 15% reduction from its baseline in 2016 and to a 20% reduction in 2017. The existing compliance mechanisms will remain, including the ability to purchase Climate Change and Emissions Management Fund Credits (Fund Credits). However, the costs of the Fund Credits will increase from $15/tonne to $20/tonne in 2016 and $30/tonne in 2017. The SGER is currently in effect until the end of 2017, at which point in time it is expected to be amended or replaced.

Suncor's Oil Sands Base plant, MacKay River plant, Firebag operations and the Edmonton refinery continue to comply with SGER. For the 2014 compliance year, the total cost to comply with the SGER was approximately $7 million. Compliance was achieved through reduced emissions per unit of production, retirement of internally generated offset credits and emission performance credits (EPCs). The cost of compliance was slightly lower than if all of the required reductions had been met through the purchase of $15/tonne of Fund Credits due to the realized cost of purchasing emission offsets and retiring EPCs. For the 2015 compliance year, the total compliance costs to Suncor are estimated to be between $8 million and $12 million, based on a cost of $15/tonne of CO_{2e}.

Several Canadian provinces (including British Columbia, Ontario and Quebec) are members of the Western Climate Initiative (WCI), a multi-jurisdictional partnership, whose members also include individual U.S. states. WCI was created in 2007 to address climate change with the initiative to reduce GHG emissions at the regional level to 15% below 2005 levels by 2020.

The Province of British Columbia enacted a carbon tax in 2008, which is capped at $30/tonne of CO_{2e} through 2018. This carbon tax is revenue neutral, in that revenues are recycled back to taxpayers via tax reductions, and is applied on consumption. Suncor's natural gas production and gathering facilities, and refined product distribution terminals in B.C. do not exceed the 25,000 tonne reporting threshold under these regulations. The purchaser or user of fuels pays the B.C. carbon tax, which is collected by Suncor and forwarded on to the government.

Quebec's cap-and-trade system is linked to the WCI. Allowances and offsets are fungible across the WCI. Suncor's Montreal refinery is subject to Quebec's cap-and-trade system for both its stationary GHG emissions because it produces more than 25,000 tonnes of CO_{2e} per year and for emissions from transportation fuels effective January 1, 2015. Emitters are required to either reduce their emissions or purchase eligible compliance mechanisms to cover their emissions above a specified cap. The cap and the allocation of free allowances are established by Quebec. For the 2014 compliance year, the total cost to comply under the Quebec cap-and-trade system was approximately $1 million. For the 2015 compliance year, the projected total compliance costs are estimated to be approximately $61 million, consisting of $60 million to cover emissions attributed to the distribution of transportation fuels and less than $1 million attributed to the Montreal refinery's stationary emissions. The majority of the compliance costs covering the emissions from transportation fuels have been passed through to the consumer, resulting in an estimated net compliance cost of approximately $1 million.

Ontario will be joining the WCI by 2017. In consultation with the industrial sector, Ontario is currently developing the framework and design of its cap-and-trade system with consideration to energy-intensive trade-exposed sectors. Suncor's lubricants plant in Mississauga and its Sarnia refinery will be subject to the cap-and-trade system. Compliance is expected to be similar to Quebec where Suncor's Sarnia refinery will be subject to both stationary GHG emissions in addition to emissions from the distribution of transportation fuels.

In the fall of 2015, the premiers of Ontario and Quebec signed two new, non-binding memorandums of understanding and made commitments on shared priorities, including climate change. Climate change priorities include close co-operation on the development and adoption of new offset credit protocols to expand the potential for GHG emissions reductions across both provinces. Suncor supports the linking of carbon markets and the use of offset credits.

U.S. GHG Regulations

The U.S. supports a clean energy standard that would reduce GHG emissions from the power sector and increase the use of cleaner sources of energy, including natural gas, nuclear power and "clean" coal. The U.S. continues to advance the 2013 Climate Action Plan to reduce GHG emissions. In the absence of other federal legislation on GHG emissions, the current administration of the United States is endorsing the U.S. Environmental Protection Agency (EPA) to regulate GHG emissions under the *Clean Air Act*, starting with the thermal power sector. The implications on the oil and gas industry being regulated under the EPA and the timing of such regulations remain unknown. In the meantime, the EPA has implemented a mandatory GHG reporting rule for all large facilities (emitting greater than 25,000 tonnes of CO_{2e} per year), which includes Suncor's refinery in Commerce City, Colorado.

The EPA has also mandated Renewable Fuel Standards 2, which encourages ethanol blending of up to 15% from the current 10% limit. Several factors will impact the ability of refiners and producers to achieve these requirements, including the lead time required for fleet turnover, the ability of retail stations to simultaneously provide both 10% and 15% fuels, and the inherent liability for ensuring consumers use the appropriate fuel for their vehicle.

California state's AB32 legislation provides for a Low Carbon Fuel Standard (LCFS). AB32 requires California to reduce its GHG emissions to 1990 levels by 2020. In September 2015, California passed SB350 which provides that 50% renewables make up the state's power supply by 2030 and for a 50% increase in energy efficiency in buildings by 2030. The bill's earlier provision requiring petroleum use consumption to be reduced by 50% by 2030 was removed from the final bill.

International Regulations

The European Union Emissions Trading Scheme (EU ETS) applies to Suncor's non-operated offshore assets in the U.K. and Norway sectors of the North Sea. The EU ETS requires that member countries set emissions limits for installations in their country covered by the scheme and assigns such installations an emissions cap. Installations may meet their cap by reducing emissions or by buying allowances from other participants. Phase III of EU ETS includes a transition from free allocation to auctioning allowances.

As part of its ongoing business planning, Suncor assesses potential costs associated with carbon dioxide (CO_2) emissions in its operations and the evaluation of future projects, based on the company's current understanding of pending and possible GHG regulations. Both the U.S. and Canada have indicated that climate change policies that may be implemented will attempt to balance economic, environmental and energy security concerns. The company expects that regulation will continue to evolve with a moderate carbon price signal, and that the price regime will progress cautiously. Suncor will continue to review the impact of future carbon-constrained scenarios on its strategy, using a price range of \$20 to \$60/tonne of CO_{2e} as a base case, applied against a range of policy options and price sensitivities.

Land Use

In 2012, the Government of Alberta approved the LARP, which covers land-use restrictions in the Lower Athabasca region of Alberta, which includes leases in Suncor's Oil Sands segment. The LARP, developed as part of the Land-Use Framework under the *Alberta Land Stewardship Act*, identifies new conservation areas, as well as management frameworks to ensure the continued regional quality of air, surface water and groundwater. The new conservation areas do not overlap any of Suncor's leases. The management frameworks formalize a number of regulatory tools that are already used by the government to manage environmental aspects of oil sands development, including the use of environmental cumulative effects management on a regional scale, and may require Suncor to have greater participation in the overall evaluation of environmental issues and emissions in the Lower Athabasca region. The frameworks include the following:

- **Air quality.** The framework is designed to maintain flexibility and to manage cumulative effects of development on air quality within the region, setting triggers and limits for nitrogen dioxide (NO_2) and sulphur dioxide (SO_2). The framework includes ambient air quality triggers and limits. Regulatory actions will occur when triggers or limits are reached or exceeded.
- **Surface water quality.** The framework builds on, but does not replace, existing provincial legislation and policy on water quality, and provides a framework in which to monitor and manage long-term, cumulative changes in water quality within the Lower Athabasca River. The framework includes quality limits and triggers for various indicators, based on existing Alberta, Canadian Council of Ministers of the Environment, Health Canada and U.S. EPA guidelines. Regulatory actions will occur when triggers or limits are reached or exceeded.
- **Groundwater.** The framework aims to manage non-saline groundwater resources in a sustainable manner and protect resources from contamination and over-use. The framework aims to ensure timely detection of key changes to indicators and describes the management response that will be initiated if triggers or limits, including site-specific measures, are reached or exceeded.
- **Surface Water Quantity Management Framework (Framework).** The Surface Water Quantity Management Framework released in March 2015 established weekly management triggers and water withdrawal limits that will be used to enable proactive management of mineable oil sands water used from the Athabasca River. Weekly water withdrawal limits will reflect seasonal variability and may become more restrictive as flows in the river change. In addition, adaptive management triggers will direct a management response process. As a part of our commitment to this Framework, Suncor voluntarily agreed to minimize water withdrawals for our existing Oil Sands Base plant operations to half of our maximum allowable withdrawal limit from 4 m3/s to 2 m3/s. For our future operations at Fort Hills, we have on-site water storage and will manage water withdrawal as per the Framework.
- **Tailings Management Framework (TMF).** This framework, released in March 2015, provides direction to manage fluid tailings volumes during and after mine operation in order to manage and mitigate liability and environmental risk resulting from the accumulation of fluid tailings on the landscape. It is anticipated that the TMF will result in technological innovations in tailings management and reduce the overall volumes of fluid fine tailings associated with oil sands mining and extraction. Requirements under the TMF for the mineable Athabasca oil sands will be administered primarily through the *Oil Sands Conservation Act* and the *Environmental Protection and Enhancement Act*. The framework uses fluid tailings volume triggers and a limit on volumes, as well as management actions to support an overarching policy objective of reducing the

amount of fluid tailings on the landscape more quickly, and of having tailings ready to reclaim within an acceptable time frame.

Suncor is committed to reclaiming and remediating lands affected by our operations. In the past few years, we have improved our tailings management efforts and became the first company to reclaim an oil sands tailings pond. As a part of the new TMF, we are now required to develop new Tailings Management Plans for our Oil Sands Base mine operations and Fort Hills facilities to meet the TMF and the Alberta Energy regulator's new Tailings Directive. These plans will be aligned with Suncor's principles on tailings:

- To establish tailings plans that have considered and incorporate stakeholder interests and feedback;
- To establish stable closure landscapes integrated into the regional ecosystem;
- To ensure land is reclaimed permanently as early as practical;
- To manage economic value and minimize life-cycle environmental impacts from today to closure; and
- To recognize the importance of flexibility and choices throughout the mine life.

Additional frameworks for Biodiversity Management and a Land Management Plan are expected to be finalized and released in 2016.

Reclamation

The Government of Alberta's Mine Financial Security Program (MFSP) holds oil sands miners responsible for all aspects of the remediation and surface reclamation work at their mine sites, and for the custody of the site until a reclamation certificate has been issued by the government. The MFSP requires a base amount of security for each project, which Suncor has provided in the form of letters of credit, and which would provide the funds necessary to safely secure and reclaim the site. Suncor is in compliance with the MFSP. Additional security may be required under other conditions, such as failure to meet current reclamation plans, or when the estimated remaining production life of the mine reaches certain levels; however, Suncor has not been required to provide any additional security to date. The MFSP has been designed by the Government of Alberta to include a periodic review of the program to ensure it is functioning properly and provide early warning of any potential risks. The MFSP is expected to be revised in 2016 in relation to the TMF.

Joint Canada – Alberta Implementation Plan for Oil Sands Monitoring

In 2012, Canada and Alberta adopted the Joint Canada-Alberta Implementation Plan for Oil Sands Monitoring (Monitoring Plan). The intent of the Monitoring Plan is to provide scientifically rigorous, comprehensive, integrated and transparent environmental monitoring, including an improved understanding of the cumulative environmental impact of oil sands development. The total costs to the industry of enhanced monitoring under the Monitoring Plan have been estimated at approximately $50 million per year. The costs to Suncor under the Monitoring Plan are estimated at approximately $10 million per year.

Alberta has since created the Alberta Environmental Monitoring, Evaluation and Reporting Agency (AEMERA), which will steward the Monitoring Plan on behalf of the province and in conjunction with the Government of Canada.

Industry Collaboration Initiatives

For areas of environmental concern, the need for energy companies to increase collaboration with each other, and with their respective stakeholders, is an important focus for the oil sands industry. Suncor is a founding member of COSIA and is committed to collaborative action to accelerate improvements in environmental performance, including tailings, water, land and GHG emissions. COSIA works with other collaborative networks to share knowledge and expertise about new technologies and innovation related to environmental performance.

RISK FACTORS

Suncor is committed to a proactive program of enterprise risk management intended to enable decision-making through consistent identification of risks inherent to its assets, activities and operations. Some of these risks are common to operations in the oil and gas industry as a whole, while some are unique to Suncor. The company's enterprise risk committee (ERC), comprised of senior representatives from business and functional groups across Suncor, oversees entity-wide processes to identify, assess and report on the company's principal risks.

Volatility of Commodity Prices

Our financial performance is closely linked to prices for crude oil in our upstream business and prices for refined petroleum products in our downstream business, and, to a lesser extent, to natural gas prices in our upstream business, where natural gas is both an input and output of production processes. The prices for all of these commodities can be influenced by global and regional supply and demand factors, which are factors that are beyond our control and can result in a high degree of price volatility.

Crude oil prices are also affected by, among other things, global economic health and global economic growth (particularly in emerging markets), pipeline constraints, regional and international supply and demand imbalances, political developments, compliance or non-compliance with quotas agreed upon by OPEC members, decisions by OPEC not to impose quotas on its members, access to markets for crude oil, and weather. These factors impact the various types of crude oil and refined products differently and can impact differentials between light and heavy grades of crude oil (including blended bitumen), and between conventional and synthetic crude oil.

Refined petroleum product prices and refining margins are also affected by, among other things, crude oil prices, the availability of crude oil and other feedstock, levels of refined product inventories, regional refinery availability, marketplace competitiveness, and other local market factors. Natural gas prices in North America are affected primarily by supply and demand, and by prices for alternative energy sources. Decreases in refined product margins or increases in natural gas prices could have a material adverse effect on Suncor's financial condition and reserves.

In addition, oil and natural gas producers in North America, and particularly in Canada, may receive discounted prices for their production relative to certain international prices, due to constraints on the ability to transport and sell such products to international markets. A failure to resolve such constraints may result in continued discounted or reduced commodity prices realized by oil and natural gas producers such as Suncor. Suncor's reserves include significant quantities of bitumen and synthetic crude oil that trade at a discount to light and medium crude oil. Bitumen and synthetic crude oil are typically more expensive to produce and process. In addition, the market prices for these products may differ from the established market indices for light and medium grades of crude oil. As a result, the price received for bitumen and synthetic crude oil may differ from the benchmark they are priced against. Future quality differentials are uncertain and a significant increase could have a material adverse effect on Suncor's financial condition.

Through the latter half of 2014 and into 2016, world oil prices have declined significantly. A prolonged period of low and/or volatile prices could affect the value of our upstream and downstream assets and the level of spending on growth projects, and could result in the curtailment of production from some properties and/or the impairment of that property's carrying value. Accordingly, low commodity prices, particularly for crude oil, could have a material adverse effect on Suncor's business, financial condition, reserves, and may also lead to the impairment of assets, or the cancellation or deferral of Suncor's growth projects.

Government Policy

Suncor operates under federal, provincial, state and municipal legislation in numerous countries. The company is also subject to regulation and intervention by governments in oil and gas industry matters, such as land tenure, royalties, taxes (including income taxes), government fees, production rates, environmental protection controls, safety performance, the reduction of GHG and other emissions, the export of crude oil, natural gas and other products, the company's interactions with foreign governments, the awarding or acquisition of exploration and production rights, oil sands leases or other interests, the imposition of specific drilling obligations, control over the development and abandonment of fields and mine sites (including restrictions on production) and possibly expropriation or cancellation of contract rights.

Changes in government policy or regulation, or interpretation thereof, could impact Suncor's existing and planned projects as well as impose costs on compliance resulting in increased capital expenditures and operating expenses. Changes in government policy or regulation or third party opposition to projects, including Northern Gateway and Energy East proposals, could also have an adverse impact on Suncor's operations. The result of such changes can also lead to additional compliance costs and staffing and resource levels, and also increase exposure to other risks to Suncor's business, including environmental or safety non-compliance and permit approvals.

Income Taxes

Increases in income taxes, such as the increase in the second quarter of 2015 in the Alberta provincial corporate income tax rate from 10% to 12% effective July 1, 2015, could have a material adverse effect on Suncor's financial condition. Pursuant to the previously disclosed 2013 proposal letter from the Canada Revenue Agency (CRA), the company received a Notice of Reassessment (NOR) from the CRA during the second quarter of 2014, regarding the income tax treatment of realized losses in 2007 on the settlement of certain derivative contracts. The total amount of the NOR, including tax, penalty and interest, was approximately $920 million. The company strongly disagrees with the CRA's position and continues to firmly believe it will be able to successfully defend its original filing position and will take the appropriate actions to resolve this matter. In addition to the above, the company has:

- Received NORs related to the derivative contracts from the Provinces of Alberta, Ontario and Quebec for approximately $124 million, $100 million and $42 million, respectively;
- Provided security to the CRA and the Provinces of Quebec and Ontario for approximately $642 million;
- Filed Notices of Objection with the CRA and the Provinces of Alberta, Ontario and Quebec; and
- Filed a Notice of Appeal with the Tax Court of Canada in November 2014 and is now pursuing its Appeal to that Court.

If the company is unsuccessful in defending its tax filing position, it could be subject to an earnings and cash impact of up to $1.2 billion.

Royalties

Royalties can be impacted by changes in crude oil and natural gas pricing, production volumes, and capital and operating costs by changes to existing legislation or PSCs, and by results of regulatory audits of prior year filings and other unexpected events. The final determination of these events may have a material impact on the company's royalties expense.

The occurrence of any of the foregoing could have a material adverse effect on Suncor's business, financial condition, reserves, results of operations and cash flow.

Operational Outages and Major Environmental or Safety Incidents

Each of Suncor's primary operating businesses – Oil Sands, E&P, and Refining and Marketing – requires significant levels of investment in the design, operation and maintenance of facilities and, therefore, carries the additional economic risk associated with operating reliably or enduring a protracted operational outage.

The company's businesses also carry the risks associated with environmental and safety performance, which is closely scrutinized by governments, the public and the media, and could result in a suspension of or inability to obtain regulatory approvals and permits, or, in the case of a major environmental or safety incident, fines, civil suits or criminal charges against the company.

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

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

In addition to the foregoing factors that affect Suncor's business generally, each business unit is susceptible to additional risks due to the nature of its business, as follows:

- Oil Sands operations are susceptible to loss of production, slowdowns, shutdowns or restrictions on our ability to produce higher value products, due to the failure of any one or more of its interdependent component systems;
- For Suncor's upstream businesses, there are risks and uncertainties associated with drilling for oil and natural gas, the operation and development of such properties and wells (including encountering unexpected formations, pressures, ore grade qualities, or the presence of hydrogen sulphide), premature declines of reservoirs, sour gas releases, uncontrollable flows of crude oil, natural gas or well fluids, other accidents, and pollution and other environmental risks. Refer also to Significant Risk Factors and Uncertainties Affecting Reserves Data;
- E&P offshore operations occur in areas subject to hurricanes and other extreme weather conditions, such

as winter storms, pack ice, icebergs and fog. The occurrence of any of these events could result in production shut-ins, the suspension of drilling operations, damage to or destruction of the equipment involved and injury or death of rig personnel. Suncor's offshore operations could also be affected by the actions of Suncor's contractors, joint venture operators and agents that could result in similar catastrophic events at their facilities, or could be indirectly affected by catastrophic events occurring at other third-party offshore operations. In either case, this could give rise to liability, damage to the company's equipment, harm to individuals, force a shutdown of our facilities or operations, or result in a shortage of appropriate equipment or specialists required to perform our planned operations; and

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

Although the company maintains a risk management program, which includes an insurance component, such insurance may not provide adequate coverage in all circumstances, nor are all such risks insurable. It is possible that our insurance coverage will not be sufficient to address the costs arising out of the allocation of liabilities and risk of loss arising from Suncor operations.

The occurrence of any of the foregoing could have a material adverse effect on Suncor's business, financial condition, results of operations and cash flow.

Regulatory Approval and Compliance

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

As part of ongoing operations, the company is also required to comply with a large number of EH&S regulations under a variety of Canadian, U.S., U.K. and other foreign, federal, provincial, territorial, state and municipal laws and regulations. Failure to comply with these regulations may result in the imposition of fines and penalties, production constraints, reputational damage, operating and growth permit applications, censure, liability for cleanup costs and damages, and the loss of important licences and permits.

Failure to obtain, comply with or maintain regulatory permits and approvals, or failure to obtain them on a timely basis or on satisfactory terms, could result in delays, abandonment or restructuring of projects and increased costs, all of which could have a material adverse effect on Suncor's business, financial condition, reserves, results of operations and cash flow.

Project Execution

There are certain risks associated with the execution of our major projects and the commissioning and integration of new facilities within our existing asset base.

Project execution risk consists of three related primary risks:

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

Project execution can also be impacted by:

- Failure to comply with Suncor's project implementation model;
- The availability, scheduling and cost of materials, equipment and qualified personnel;
- The complexities associated with integrating and managing contractor staff and suppliers in a confined construction area;
- Our ability to obtain the necessary environmental and other regulatory approvals;
- The impact of general economic, business and market conditions and our ability to finance growth, including major growth projects in progress, if commodity prices were to decline and stay at low levels for an extended period;
- The impact of weather conditions;
- Risks relating to restarting projects placed in safe mode, including increased capital costs;
- The effect of changing government regulation and public expectations in relation to the impact of oil sands development on the environment;
- Risks associated with offshore fabrication and logistics;

- Risks relating to scheduling, resources and costs, including the availability and cost of materials, equipment and qualified personnel;
- The accuracy of project cost estimates, as actual costs for major projects can vary from estimates, and these differences can be material;
- Our ability to complete strategic transactions; and
- The commissioning and integration of new facilities within our existing asset base could cause delays in achieving guidance, targets and objectives.

The occurrence of any of the foregoing could have a material adverse effect on Suncor's business, financial condition, reserves, results of operations and cash flow.

Fossil Fuel Industry Reputation

Suncor works within an environment characterized by concerns over climate change, with environmental limits seen as a legitimate constraint on economic growth and increased activism and public opposition to fossil fuels. In addition, the social value proposition of resource deployment is being challenged.

Future laws and regulations may impose significant liabilities on a failure to comply with their requirements. Concerns over climate change and fossil fuel extraction could lead governments to enact additional or more stringent laws and regulations applicable to Suncor and other companies in the energy industry.

Changes in environmental regulation could impact the demand, formulation or quality of our products, or by requiring increased capital expenditures or distribution costs, which may or may not be recoverable in the marketplace. The complexity and breadth of changes in environmental regulation make it extremely difficult to predict the potential impact to Suncor.

Climate Change

Suncor continues to actively monitor the international and domestic efforts to address climate change. While it currently appears that GHG regulations and targets will continue to become more stringent, and while Suncor will continue efforts to reduce the intensity of its GHG emissions, the absolute GHG emissions of our company are expected to rise as we pursue a growth strategy. Increases in GHG emissions may impact the profitability of our projects, as Suncor may be subject to incremental levies and taxes.

Land Reclamation

There are risks associated specifically with the company's ability to reclaim mature fine tailings, with TRO™ or other methods and technologies. Suncor expects that TRO™ will help the company reclaim existing tailings ponds by reducing the volumes of fluid fine tailings. The inability of TRO™ or any other methods of technology and/or the increase in time to reclaim tailings ponds could increase Suncor's decommissioning and restoration cost estimates.

Alberta's Land-Use Framework

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

Alberta Environment Water Licences

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

There is a risk that future laws or changes to existing laws or regulations could cause capital expenditures and operating expenses to increase or the demand for our products to decrease. There is also a risk that Suncor could face litigation initiated by third parties relating to climate change.

The occurrence of any of the foregoing could have a material adverse effect on Suncor's business, financial condition, results of operations and cash flow.

Change Capacity

In order to achieve Suncor's business objectives, the company must operate efficiently, reliably and safely, and, at the same time, deliver growth and sustaining projects safely, on budget and on schedule. The ability to achieve these two sets of objectives is critically important to Suncor to deliver value to shareholders and stakeholders. These objectives also demand a large number of improvement initiatives that compete for resources, and may negatively impact the company should there be inadequate consideration of the cumulative impacts of prior and parallel initiatives on people, processes and systems. There is also a risk that these objectives may exceed Suncor's capacity to adopt and implement change. The occurrence of any of the foregoing could have a material adverse effect on Suncor's business, financial condition, results of operations and cash flow.

Cost Management

Suncor is exposed to the risk of escalating operating costs. Suncor's inability to successfully manage costs may constrain its ability to execute high-quality projects that deliver lower operating costs. Factors contributing to these risks include, but are not limited to, the skills and resource shortage and the long-term success of existing and new in situ technologies. The risk of escalating operating costs could have a material adverse effect on Suncor's business, financial condition, reserves, results of operations and cash flow.

Market Access

Suncor anticipates higher production of bitumen in future years, due mainly to production growth from Fort Hills. The markets for bitumen blends or heavy crude are more limited than those for light crude, making them more susceptible to supply and demand changes and imbalances (whether as a result of the availability, proximity, and capacity of pipeline facilities, railcars, or otherwise). Heavy crude oil generally receives lower market prices than light crude, due principally to the lower quality and value of the refined product yield and the higher cost to transport the more viscous product on pipelines, and this price differential can be amplified due to supply and demand imbalances. A shortage of condensate to transport bitumen may cause Suncor's cost to increase due to the need to purchase alternative diluent supplies, thereby increasing the cost to transport bitumen to market and increasing Suncor's operating cost, as well as affecting Suncor's bitumen blend marketing strategy.

There is a risk that constrained market access for oil sands production, due to insufficient pipeline takeaway capacity, growing inland production and refinery outages, creates risk of widening differentials that could impact the profitability of product sales, which could have a material adverse effect on our business, financial condition, reserves, results of operations and cash flow.

Information Security

The efficient operation of Suncor's business is dependent on computer hardware and software systems. Information systems are vulnerable to security breaches by computer hackers and cyberterrorists. We rely on industry-accepted security measures and technology to securely maintain confidential and proprietary information stored on our information systems. However, these measures and technology may not adequately prevent security breaches. There is a risk that any significant interruption or the failure of these systems to perform as anticipated for any reason could disrupt our business and could result in decreased performance, production, or increased costs, and could have a material adverse effect on Suncor's business, financial condition, results of operations and cash flow.

In the ordinary course of Suncor's business, Suncor collects and stores sensitive data, including intellectual property, proprietary business information and personally identifiable information of our employees and retail customers. Despite Suncor's security measures, Suncor's information technology and infrastructure may be vulnerable to attacks by hackers and cyberterrorists or breached due to employee error, malfeasance or other disruptions. Any such breach could compromise Suncor's networks and the information Suncor stores could be accessed, publicly disclosed, lost or stolen. Any such access, disclosure or other loss of information could result in legal claims or proceedings, liability under laws that protect the privacy of personal information, regulatory penalties, disrupt Suncor's operations and damage Suncor's reputation, which could have a material adverse effect on Suncor's business, financial condition, results of operations and cash flow.

Financial Risks

Energy Trading and Risk Management Activities and the Exposure to Counterparties

The nature of Suncor's energy trading and risk management activities, which may make use of derivative financial instruments to hedge its commodity price and other market risks, creates exposure to significant financial risks, which include, but are not limited to, the following:

- Unfavourable movements in commodity prices, interest rates or foreign exchange could result in a financial or opportunity loss to the company;
- A lack of counterparties, due to market conditions or other circumstances, could leave us unable to liquidate or offset a position, or unable to do so at or near the previous market price;
- We may not receive funds or instruments from our counterparty at the expected time or at all;
- The counterparty could fail to perform an obligation owed to us;
- Loss as a result of human error or deficiency in our systems or controls; and
- Loss as a result of contracts being unenforceable or transactions being inadequately documented.

The occurrence of any of the foregoing could have a material adverse effect on Suncor's business, financial condition, results of operations and cash flow.

Exchange Rate Fluctuations

Our audited Consolidated Financial Statements are presented in Canadian dollars. The majority of Suncor's revenues from the sale of oil and natural gas are based on prices that are determined by, or referenced to, U.S. dollar benchmark prices, while the majority of Suncor's expenditures are realized in Canadian dollars. The company also holds substantial amounts of U.S. dollar debt. Suncor's results, therefore, can be affected significantly by the exchange rates between the Canadian dollar and the U.S. dollar. The company also undertakes operations administered through international subsidiaries and, so, to a lesser extent, Suncor's results can be affected by the exchange rates between the Canadian dollar and the euro, and the Canadian dollar and the British pound. These exchange rates may vary substantially and may give rise to favourable or unfavourable foreign currency exposure. A decrease in the value of the Canadian dollar relative to the U.S. dollar will increase the revenues received from the sale of commodities. An increase in the value of the Canadian dollar relative to the U.S. dollar will decrease revenue received from the sale of commodities. A decrease in the value of the Canadian dollar relative to the U.S. dollar from the previous balance sheet date increases the amount of Canadian dollars required to settle U.S. dollar denominated obligations. In 2015, the Canadian dollar weakened in relation to the U.S. dollar to 0.72 from 0.86.

The occurrence of any of the foregoing could have a material adverse effect on Suncor's business, financial condition, results of operations and cash flow.

Interest Rate Risk

We are exposed to fluctuations in short-term Canadian and U.S. interest rates as Suncor maintains a portion of its debt capacity in revolving and floating rate bank facilities and commercial paper, and invests surplus cash in short-term debt instruments. We are also exposed to interest rate risk when debt instruments are maturing and require refinancing, or when new debt capital needs to be raised. Unfavourable changes in interest rates could have a material adverse effect on Suncor's business, financial condition, results of operations and cash flow.

Issuance of Debt and Debt Covenants

Suncor expects that future capital expenditures will be financed out of cash generated from operations and borrowings. This ability is dependent on, among other factors, commodity prices, the overall state of the capital markets and investor appetite for investments in the energy industry generally and our securities in particular. To the extent that external sources of capital become limited or unavailable or available on unfavourable terms, our ability to make capital investments and maintain existing properties may be constrained.

If we finance capital expenditures in whole or in part with debt, that may increase our debt levels above industry standards for oil and gas companies of similar size. Depending on future development plans, we may require additional debt financing that may not be available or, if available, may not be available on favourable terms, including higher interest rates and fees. Neither the articles of Suncor (the Articles) nor its bylaws limit the amount of indebtedness that we may incur; however, we are subject to covenants in our existing bank facilities and seek to avoid an unfavourable cost of debt. The level of our indebtedness, from time to time, could impair our ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise and could negatively affect our credit ratings.

We are required to comply with financial and operating covenants under existing credit facilities and debt securities. We routinely review the covenants based on actual and forecast results and have the ability to make changes to our development plans, capital structure and/or dividend policy to comply with covenants under the credit facilities. If Suncor does not comply with the covenants under its credit facilities and debt securities, there is a risk that repayment could be accelerated and/or the company's access to capital could be restricted or only be available on unfavourable terms.

Rating agencies regularly evaluate the company and our subsidiaries. Their ratings of our long-term and short-term debt are based on a number of factors, including our financial strength, as well as factors not entirely within our control, including conditions affecting the oil and gas industry generally, and the wider state of the economy. Credit ratings may be important to customers or counterparties when we compete in certain markets and when we seek to engage in certain transactions, including transactions involving over-the-counter derivatives. There is a risk that one or more of our credit ratings could be downgraded, which could potentially limit our access to private and public credit markets and increase the company's cost of borrowing. On February 12, 2016, Moody's Investors Service downgraded Suncor's senior unsecured debt from A3 to Baa1. In addition, Suncor's outlook has been placed under credit watch by Standard & Poor's and under review by Dominion Bond Rating Service.

The occurrence of any of the foregoing could have a material adverse effect on Suncor's business, financial condition, reserves, results of operations and cash flow.

Third-Party Service Providers

Suncor is reliant on the operational integrity of a large number of third-party service providers, including input and output commodity transport (pipelines, rail, trucking, marine) and utilities associated with various Suncor facilities, including electricity. A disruption in service by one of these third parties can also have a dramatic impact on Suncor's operations. Pipeline constraints that affect takeaway capacity or supply of inputs, such as hydrogen and power for example, could impact our ability to produce at capacity levels. Disruptions in pipeline service could adversely affect commodity prices, Suncor's price realizations, refining operations and sales volumes, or limit our ability to produce and deliver production. These interruptions may be caused by the inability of the pipeline to operate or by the oversupply of feedstock into the system that exceeds pipeline capacity. There can be no certainty that short-term operational constraints on pipeline systems arising from pipeline interruption and/or increased supply of crude oil will not occur. There is a risk that third-party outages could impact Suncor's production or price realizations, which could have a material adverse effect on Suncor's business, financial condition, results of operations and cash flow.

Foreign Operations

The company has operations in a number of countries with different political, economic and social systems. As a result, the company's operations and related assets are subject to a number of risks and other uncertainties arising from foreign government sovereignty over the company's international operations, which may include, among other things:

- Currency restrictions and restrictions on repatriation of funds;
- Loss of revenue, property and equipment as a result of expropriation, nationalization, war, insurrection and geopolitical and other political risks;
- Increases in taxes and government royalties;
- Compliance with existing and emerging anti-corruption laws, including the *Foreign Corrupt Practices Act* (United States), the *Corruption of Foreign Officials Act* (Canada) and the United Kingdom *Bribery Act*;
- Renegotiation of contracts with government entities and quasi-government agencies, including risks regarding negotiations in Libya with the NOC related to the periods in which Suncor is in force majeure under its EPSAs;
- Changes in laws and policies governing operations of foreign-based companies; and
- Economic and legal sanctions (such as restrictions against countries experiencing political violence, or countries that other governments may deem to sponsor terrorism).

If a dispute arises in the company's foreign operations, the company may be subject to the exclusive jurisdiction of foreign courts or may not be able to subject foreign persons to the jurisdiction of a court in Canada or the U.S. In addition, as a result of activities in these areas and a continuing evolution of an international framework for corporate responsibility and accountability for international crimes, there is a risk the company could also be exposed to potential claims for alleged breaches of international law.

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

Despite Suncor's training and policies around bribery and other forms of corruption, there is a risk that Suncor, or some of its employees or contractors, could be charged with bribery or corruption. Any of these violations could result in onerous penalties. Even allegations of such behaviour could impair Suncor's ability to work with governments or non-government organizations and could result in the formal exclusion of Suncor from a country or area, sanctions, fines, project cancellations or delays, the inability to raise or borrow capital, reputational impacts and increased investor concern.

The occurrence of any of the foregoing could have a material adverse effect on Suncor's business, financial condition, results of operations and cash flow.

Joint Arrangement Risk

Suncor has entered into joint arrangements and other contractual arrangements with third parties with respect to certain of its projects where other entities operate assets in which Suncor has ownership or other interests. The success and timing of Suncor's activities on assets and projects operated by others, or developed jointly with others, depend upon a number of factors that are outside of Suncor's control, including the timing and amount of capital expenditures, the timing and amount of operational and maintenance expenditures, the operator's expertise, financial resources and risk management practices, the approval of other participants, and the selection of technology.

These co-owners may have objectives and interests that do not coincide with and may conflict with Suncor's interests.

Major capital decisions affecting joint arrangements may require agreement among the co-owners, while certain operational decisions may be made solely at the discretion of the operator of the applicable assets. While joint venture counterparties may generally seek consensus with respect to major decisions concerning the direction and operation of the assets and the development of projects, no assurance can be provided that the future demands or expectations of the parties relating to such assets and projects will be met satisfactorily or in a timely manner. Failure to satisfactorily meet demands or expectations by all of the parties may affect our participation in the operation of such assets or in the development of such projects, our ability to obtain or maintain necessary licences or approvals, or the timing for undertaking various activities. In addition, disputes may arise pertaining to the timing and/or capital commitments with respect to projects that are being jointly developed, which could materially adversely affect the development of such projects and Suncor's business and operations.

The occurrence of any of the foregoing could have a material adverse effect on Suncor's business, financial condition, reserves, results of operations and cash flow.

Technology Risk

There are risks associated with growth and other capital projects that rely largely or partly on new technologies and the incorporation of such technologies into new or existing operations, including that the results of the application of new technologies may differ from simulated or test environments. The success of projects incorporating new technologies cannot be assured. Advantages accrue to companies that can develop and adopt emerging technologies in advance of competitors. The inability to develop, implement and monitor new technologies may impact the company's ability to develop its new or existing operations in a profitable manner, which could have a material adverse effect on Suncor's business, financial condition, results of operations and cash flow.

Skills, Resource Shortage and Reliance on Key Personnel

The successful operation of Suncor's businesses and our ability to expand operations will depend upon the availability of, and competition for, skilled labour and materials supply. There is a risk that we may have difficulty sourcing the required labour for current and future operations. The risk could manifest itself primarily through an inability to recruit new staff without a dilution of talent, to train, develop and retain high-quality and experienced staff without unacceptably high attrition, and to satisfy an employee's work/life balance and desire for competitive compensation. The labour market in Alberta has been historically tight, and while the current economic situation has partially moderated this effect, it remains a risk to be managed. The increasing age of our existing workforce adds further pressure. Materials may also be in short supply due to smaller labour forces in many manufacturing operations. Our ability to operate safely and effectively and complete all our projects on time and on budget has the potential to be significantly impacted by these risks and this impact could be material.

Our success also depends in large measure on certain key personnel. The loss of the services of such key personnel could have a material adverse effect on the company. The contributions of the existing management team to the immediate and near-term operations of the company are likely to continue to be of central importance for the foreseeable future.

Labour Relations

Hourly employees at our Oil Sands facilities, all of our refineries, certain of our lubricants operations, certain of our terminal and distribution operations, and our Terra Nova FPSO are represented by labour unions or employee associations. Approximately 34% of the company's employees were covered by collective agreements at the end of 2015. The majority of collective agreements, covering approximately 4,152 employees represented by Unifor, expire in 2016. Any work interruptions involving our employees (including as a result of the failure to successfully negotiate new collective agreements with Unifor), contract trades utilized in our projects or operations, or any jointly owned facilities operated by another entity, presents a significant risk to the company and could have a material adverse effect on Suncor's business, financial condition, results of operations and cash flow.

Competition

The global petroleum industry is highly competitive in many aspects, including the exploration for and the development of new sources of supply, the acquisition of crude oil and natural gas interests, and the refining, distribution and marketing of refined petroleum products. We compete in virtually every aspect of our business with other energy companies. The petroleum industry also competes with other industries in supplying energy, fuel and related products to consumers.

For Suncor's Oil Sands segment, a number of other companies have entered, or may enter, the oil sands business and begin producing bitumen and SCO, or expand their existing operations. It is difficult to assess the number, level of production and ultimate timing of all potential new projects or when existing production levels may increase. During recent years, a global focus on the oil sands through increasing industry consolidation that has created competitors with financial capacity has significantly increased the supply of bitumen, SCO and heavy crude oil in the marketplace. The impact of this level of activity on regional infrastructure, including pipelines, has placed stress on the availability and cost of all resources required to build and run new and existing oil sands operations.

For Suncor's Refining and Marketing business, management expects that fluctuations in demand for refined products, margin volatility and overall marketplace competitiveness will continue. In addition, to the extent that our downstream business unit participates in new product markets, it could be exposed to margin risk and volatility from either cost and/or selling price fluctuations.

There is a risk that increased competition could cause costs to increase, put further strain on existing infrastructure and make margins for refined and unrefined products to be volatile which could have a material adverse effect on Suncor's business, financial condition, results of operations and cash flow.

Land Claims

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

Litigation Risk

There is a risk that Suncor may be subject to litigation, and claims under such ligation may be material. Various types of claims may be raised in these proceedings, including, but not limited to, environmental damage, breach of contract, product liability, antitrust, bribery and other forms of corruption, tax, patent infringement and employment matters. Litigation is subject to uncertainty and it is possible that there could be material adverse developments in pending or future cases. Unfavourable outcomes or settlements of litigation could encourage the commencement of additional litigation. Suncor may also be subject to adverse publicity associated with such matters, regardless of whether Suncor is ultimately found liable. There is a risk that the outcome of such litigation may be materially adverse and/or we may be required to incur significant expenses or devote significant resources in defense against such litigation, the success of which cannot be guaranteed.

Dividends

Our payment of future dividends on our common shares will be dependent on, among other things, our financial condition, results of operations, cash flow, the need for funds to finance ongoing operations, debt covenants and other business considerations as the company's Board considers relevant. There can be no assurance that Suncor will continue to pay dividends in the future.

Control Environment

Based on their inherent limitations, disclosure controls and procedures and internal controls over financial reporting may not prevent or detect misstatements, and even those controls determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Failure to adequately prevent, detect and correct misstatements could have a material adverse effect on Suncor's business, financial condition, results of operations and cash flow.

DIVIDENDS

The Board of Directors has established a practice of paying dividends on a quarterly basis. Suncor reviews its ability to pay dividends from time to time with regard to the company's financial position, financing requirements for growth, cash flow and other factors. The Board approved an increase in the quarterly dividend to $0.29 per share from $0.28 per share in the first quarter of 2015. In July 2014, the Board of Directors approved a per share increase of $0.05 to Suncor's quarterly dividend to $0.28 per common share. Dividends are paid subject to applicable law, if, as and when declared by the Board.

Year ended December 31	2015	2014	2013
Cash dividends per common share ($)	**1.14**	1.02	0.73

DESCRIPTION OF CAPITAL STRUCTURE

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

As at December 31, 2015, there were 1,446,013,653 common shares issued and outstanding. To the knowledge of the Board of Directors and executive officers of Suncor, no person beneficially owns, or exercises control or direction over, securities carrying 10% or more of the voting rights attached to any class of voting securities of the company. The holders of common shares are entitled to attend all meetings of shareholders and vote at any such meeting on the basis of one vote for each common share held. Common shareholders are entitled to receive any dividend declared by the Board on the common shares and to participate in a distribution of the company's assets among its shareholders for the purpose of winding up its affairs. The holders of the common shares shall be entitled to share equally, share for share, in all distributions of such assets.

Petro-Canada Public Participation Act

The *Petro-Canada Public Participation Act* requires that the Articles of Suncor include certain restrictions on the ownership and voting of voting shares of the company. The common shares of Suncor are voting shares. No person, together with associates of that person, may subscribe for, have transferred to that person, hold, beneficially own or control otherwise than by way of security only, or vote in the aggregate, voting shares of Suncor to which are attached more than 20% of the votes attached to all outstanding voting shares of Suncor. Additional restrictions include provisions for suspension of voting rights, forfeiture of dividends, prohibitions against share transfer, compulsory sale of shares, and redemption and suspension of other shareholder rights. The Board may at any time require holders of, or subscribers for, voting shares, and certain other persons, to furnish statutory declarations as to ownership of voting shares and certain other matters relevant to the enforcement of the restrictions. Suncor is prohibited from accepting any subscription for, and issuing or registering a transfer of, any voting shares if a contravention of the individual ownership restrictions results.

Suncor's Articles, as required by the *Petro-Canada Public Participation Act*, also include provisions requiring Suncor to maintain its head office in Calgary, Alberta; prohibiting Suncor from selling, transferring or otherwise disposing of all or substantially all of its assets in one transaction, or several related transactions, to any one person or group of associated persons, or to non-residents, other than by way of security only in connection with the financing of Suncor; and requiring Suncor to ensure (and to adopt, from time to time, policies describing the manner in which Suncor will fulfil the requirement to ensure) that any member of the public can, in either official language of Canada (English or French), communicate with and obtain available services from Suncor's head office and any other facilities where Suncor determines there is significant demand for communication with, and services from, that facility in that language.

Credit Ratings

The following information regarding the company's credit ratings is provided as it relates to the company's cost of funds and liquidity. In particular, the company's ability to access unsecured funding markets and to engage in certain collateralized business activities on a cost-effective basis is primarily dependent upon maintaining competitive credit ratings. A lowering of the company's credit rating may also have potentially adverse consequences for the company's funding capacity for growth projects or access to the capital markets, may affect the company's ability, and the cost, to enter into normal course derivative or hedging transactions and may require the company to post additional collateral under certain contracts.

The following table shows the ratings issued by the rating agencies noted therein as of February 24, 2016. The credit ratings are not recommendations to purchase, hold or sell the debt securities inasmuch as such ratings do not comment as to the market price or suitability for a particular investor. Any rating may not remain in effect for any given period of time or may be revised or withdrawn entirely by a rating agency in the future if, in its judgment, circumstances so warrant.

	Senior Unsecured	Outlook	Canadian Commercial Paper Program	U.S. Commercial Paper Program
Standard & Poor's (S&P)	A-	Credit Watch	A-1 (low)	A-2
Dominion Bond Rating Service (DBRS)	A (low)	Under Review	R-1 (low)	Not rated
Moody's Investors Service (Moody's)	Baa1	Stable	Not rated	P-2

S&P credit ratings on long-term debt are on a rating scale that ranges from AAA to D, representing the range of such securities rated from highest to lowest quality. A rating of A by S&P is the third highest of 10 categories and indicates that the obligor had strong capacity to meet its financial commitments. However, the obligor is somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than higher rated obligors (rated AA or AAA). The addition of a plus (+) or minus (-) designation after the rating indicates the relative standing within a particular rating category. S&P credit ratings on commercial paper are on a short-term debt rating scale that ranges from A-1 to D, representing the range of such securities rated from highest to lowest quality. A Canadian rating by S&P of A-1 (low) is the third highest of eight categories and a U.S. rating of A-2 is the second highest of six categories, indicating a slightly higher susceptibility to the adverse effects of changes in circumstances and economic conditions, although the obligor's capacity to meet its financial commitment on the obligation is satisfactory.

DBRS credit ratings on long-term debt are on a rating scale that ranges from AAA to D, representing the range of such securities rated from highest to lowest. A rating of A by DBRS is the third highest of 10 categories and is assigned to debt securities considered to be of good credit quality, with the capacity for the payment of financial obligations being substantial, but of a lesser credit quality than a AA rating. Entities in the A category may be vulnerable to future events, but qualifying negative factors are considered manageable. All rating categories other than AAA and D also contain designations for (high) and (low). The absence of either a (high) or (low) designation indicates the rating is in the middle of the category. The assignment of a (high) or (low) designation within a rating category indicates relative standing within that category.

DBRS's credit ratings on commercial paper are on a short-term debt rating scale that ranges from R-1 (high) to D, representing the range of such securities rated from highest to lowest quality. A rating of R-1 (low) by DBRS is the third highest of 10 categories and is assigned to debt securities considered to be of good credit quality. The capacity for the payment of short-term financial obligations as they become due is substantial, with overall strength not as favourable as higher rating categories. Entities in this category may be vulnerable to future events, but qualifying negative factors are considered manageable. The R-1 and R-2 commercial paper categories are denoted by (high), (middle) and (low) designations.

Moody's credit ratings are on a long-term debt rating scale that ranges from Aaa to C, which represents the range from highest to lowest quality of such securities rated. A rating of Baa by Moody's is the fourth highest of nine categories. Obligations rated Baa are subject to moderate credit risk. They are considered medium grade and, as such, may possess certain speculative characteristics. For rating categories Aa through Caa, Moody's appends numerical modifiers 1, 2 or 3 to each generic rating classification. The modifier 1 indicates that the obligation ranks in the higher end of its generic rating category; the modifier 2 indicates a mid-range ranking; and the modifier 3 indicates a ranking in the lower end of that generic rating category. A rating of P-2 by Moody's for commercial paper is the second highest of four rating categories and indicates a strong ability to repay short-term obligations.

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

MARKET FOR SECURITIES

Our common shares are listed on the TSX in Canada and on the NYSE in the U.S. The price ranges and the volumes traded on the TSX for the year ended December 31, 2015 are as follows:

TSX

	Price Range (Cdn$)		Trading Volume
	High	Low	(000s)
2015			
January	38.12	33.85	77 730
February	40.60	37.25	65 923
March	37.83	34.44	68 006
April	40.93	37.10	65 413
May	39.74	35.87	51 291
June	36.81	33.43	64 887
July	37.23	32.43	61 938
August	38.19	32.13	63 719
September	36.37	33.16	76 547
October	39.17	34.40	83 608
November	40.35	36.22	63 510
December	37.80	34.03	62 085

For information in respect of options to purchase common shares of Suncor and common shares issued upon the exercise of options, see the Share Capital note to the 2015 audited Consolidated Financial Statements, which is incorporated by reference into this AIF and available on SEDAR at www.sedar.com.

DIRECTORS AND EXECUTIVE OFFICERS

Directors

The following individuals are directors of Suncor on the date hereof. The term of each director is from the date of the meeting at which he or she is elected or appointed until the next annual meeting of shareholders or until a successor is elected or appointed.

Suncor Directors Name and Jurisdiction of Residence	Period Served and Independence	Biography
Patricia M. Bedient Washington, USA	Director since 2016 Independent	Patricia Bedient is executive vice president of Weyerhaeuser Company (Weyerhaeuser), one of the world's largest integrated forest products companies. From 2007 until February 2016, she also served as chief financial officer. Prior thereto she held a variety of leadership roles in finance and strategic planning at Weyerhaeuser after joining the company in 2003. Before joining Weyerhaeuser, she spent 27 years with Arthur Andersen LLP and ultimately served as the managing partner for its Seattle office and partner in charge of the firm's forest products practice. Ms. Bedient serves on the board of directors of Alaska Air Group, the Overlake Hospital Medical Center board of trustees, the Oregon State University board of trustees, and the University of Washington Foster School of Business advisory board. She achieved national recognition in 2012 when Wall Street Journal named her one of the Top 25 CFOs in the United States. She is a member of the American Institute of CPAs and the Washington Society of CPAs. Ms. Bedient received her bachelor's degree in business administration, with concentrations in finance and accounting, from Oregon State University in 1975.
Mel E. Benson(1)(2) Alberta, Canada	Director since 2000 Independent	Mel Benson is president of Mel E. Benson Management Services Inc., an international consulting firm working in various countries with a focus on First Nations/corporate negotiations. Mr. Benson is also part owner of the private oil and gas company Tenax Energy Inc. and sits on the boards of the Fort McKay Group of Companies, a community trust organization, and Oilstone Energy Services, Inc., based in Houston, Texas. Mr. Benson retired from Exxon International and Imperial Oil Canada in 2000 after a long career as an operations manager and senior member of project management. While based in Houston, Texas, Mr. Benson worked on international projects based in Africa and the former Soviet Union. Mr. Benson is a member of Beaver Lake Cree Nation, located in northeast Alberta. In 2015, Mr. Benson was inducted into the Aboriginal Business Hall of Fame.

Suncor Directors Name and Jurisdiction of Residence	Period Served and Independence	Biography
Jacynthe Côté[(2)(3)] Québec, Canada	Director since 2015 Independent	Jacynthe Côté was president and chief executive officer of Rio Tinto Alcan, a metals and mining company, from February 2009 until June 2014 and she continued to serve in an advisory role until her retirement on September 1, 2014. Prior to 2009, she served as president and chief executive officer of Rio Tinto Alcan's Primary Metal business group, following Rio Tinto's acquisition of Alcan Inc. in October 2007. Ms. Côté joined Alcan Inc. in 1988 and she served in a variety of progressively senior leadership roles during her career, including positions in human resources, environment, health and safety, business planning and development, and production/managerial positions in Québec and England. Ms. Côté is a director of Finning International Inc. and the Royal Bank of Canada. She also serves as a member of the advisory board of the Montreal Neurological Institute and of the board of directors of École des Hautes Études Commereciales Montréal. Ms. Côté has a bachelor's degree in chemistry from Laval University.
Dominic D'Alessandro[(3)(4)] Ontario, Canada	Director since 2009 Independent	Dominic D'Alessandro was president and chief executive officer of Manulife Financial Corporation from 1994 to 2009 and is currently a director of CGI Group Inc. For his many business accomplishments, Mr. D'Alessandro was recognized as Canada's Most Respected CEO in 2004 and CEO of the Year in 2002, and was inducted into the Insurance Hall of Fame in 2008. Mr. D'Alessandro is an Officer of the Order of Canada and has been appointed as a Commendatore of the Order of the Star of Italy. In 2009, he received the Woodrow Wilson Award for Corporate Citizenship and in 2005 was granted the Horatio Alger Award for community leadership. Mr. D'Alessandro is a FCA, and holds a Bachelor of Science from Concordia University in Montreal. He has also been awarded honorary doctorates from York University, the University of Ottawa, Ryerson University and Concordia University.
W. Douglas Ford[(1)(4)] Florida, USA	Director since 2004 Independent	W. Douglas Ford was chief executive, refining and marketing for BP p.l.c. (BP) from 1998 to 2002 and was responsible for the refining, marketing and transportation network of BP as well as the aviation fuels business, the marine business and BP shipping. Mr. Ford is currently a director of Air Products and Chemicals, Inc. He is also a member of the board of trustees of the University of Notre Dame as Trustee Emeritus.

Suncor Directors Name and Jurisdiction of Residence	Period Served and Independence	Biography
John D. Gass[1][2] Florida, USA	Director since 2014 Independent	John Gass is former vice president, Chevron Corporation, a major integrated oil and gas company, and former president, Chevron Gas and Midstream, positions he held from 2003 until his retirement in 2012. He has extensive international experience, having served in a diverse series of operational positions in the oil and gas industry with increasing responsibility throughout his career. Mr. Gass serves as a director of Southwestern Energy Co. and Weatherford International Ltd. He is also on the board of visitors for the Vanderbilt School of Engineering and is a member of the advisory board for the Vanderbilt Eye Institute. Mr. Gass graduated from Vanderbilt University in Nashville, Tennessee, with a bachelor's degree in civil engineering. He also holds a master's degree in civil engineering from Tulane University in New Orleans, Louisiana. A resident of Florida, he is a member of the American Society of Civil Engineers and the Society of Petroleum Engineers.
John R. Huff[1][2] Texas, USA	Director since 1998 Independent	John Huff has served as chairman of the board of directors of Oceaneering International, Inc. (Oceaneering) since 1990 and served as its chief executive officer from 1986 to 2006. Prior to joining Oceaneering, he served as chairman, president and chief executive officer of Western Oceanic, Inc. from 1972 to 1986. Mr. Huff is also a director of Hi-Crush Partners LP and serves on the boards of trustees of Baylor College of Medicine and the Georgia Tech Foundation. Mr. Huff is a member of the National Academy of Engineering, a past member of the National Petroleum Council and a past director of the National Ocean Industries Association and the International Association of Drilling Contractors, and served on the U.S. Department of Transportation's National Offshore Safety Advisory Committee. Mr. Huff attended Rice University and received a bachelor's degree in civil engineering from the Georgia Institute of Technology, as well as attended the Harvard Business School's Program for Management Development. Mr. Huff is a registered professional engineer in the state of Texas and a member of The Explorers Club.

Suncor Directors Name and Jurisdiction of Residence	Period Served and Independence	Biography
Maureen McCaw[3][4] Alberta, Canada	Director since 2004 (Petro-Canada 2004 to July 31, 2009) Independent	Maureen McCaw was most recently executive vice-president of Leger Marketing (Alberta) and formerly president of Criterion Research, a company she founded in 1986. Ms. McCaw is chair of the Edmonton International Airport and CBC Pension Fund Plan board of trustees and is a director of the Canadian Broadcasting Corporation. She also serves on a number of other boards and advisory committees, including the Institute of Corporate Directors, the Nature Conservancy of Canada and MacEwan University, Faculty of Business, as well as being past chair of the Edmonton Chamber of Commerce. Ms. McCaw completed Columbia Business School's executive program in financial accounting and has an ICD.d.
Michael W. O'Brien[3][4] Alberta, Canada	Director since 2002 Independent	Michael O'Brien served as executive vice president, corporate development, and chief financial officer of Suncor Energy Inc. before retiring in 2002. Mr. O'Brien is a director and chair of the Audit Committee of Shaw Communications Inc. In addition, he is past chair of the board of trustees for the Nature Conservancy Canada, past chair of the Canadian Petroleum Products Institute and past chair of Canada's Voluntary Challenge for Global Climate Change. He has previously served on the boards of Terasen Inc., Primewest Energy Inc. and CRA International.
James W. Simpson Alberta, Canada	Director since 2004 (Petro-Canada 2004 to July 31, 2009) Independent	James Simpson is past president of Chevron Canada Resources (oil and gas). He serves as lead director for Canadian Utilities Limited and is on its Corporate Governance, Nomination, Compensation and Succession Committee, as well as being the chairman for its Audit Committee and Risk Review Committee. Mr. Simpson holds a Bachelor of Science and Master of Science, and graduated from the Program for Senior Executives at M.I.T.'s Sloan School of Business. He is also past chairman of the Canadian Association of Petroleum Producers and past vice chairman of the Canadian Association of the World Petroleum Congresses.
Eira M. Thomas[1][2] British Columbia, Canada	Director since 2006 Independent	Eira Thomas is a Canadian geologist with over 20 years of experience in the Canadian diamond business, including her previous roles as vice president of Aber Resources, now Dominion Diamond Corp., and as founder and CEO of Stornoway Diamond Corp. Currently, Ms. Thomas is chief executive officer and a director of Kaminak Gold Corporation, a mineral exploration company, and a director of Lucara Diamond Corp.

Suncor Directors Name and Jurisdiction of Residence	Period Served and Independence	Biography
Steven W. Williams Alberta, Canada	Director since December 2011 Non-independent, management	Steve Williams has served as the president of Suncor Energy Inc. since December 2011 and as chief executive officer of Suncor Energy Inc. since May 2012. Mr. Williams is a fellow of the Institution of Chemical Engineers and is a member of the Institute of Directors. He is one of twelve founding CEOs of COSIA and a member of the advisory board of Canada's Ecofiscal Commission. In January 2016, he was elected to the board of directors for the Business Council of Canada (formerly known as the Canadian Council of Chief Executives). Mr. Williams also serves as vice-chair of the Alberta Premier's Advisory Committee on the Economy. In November 2015, he was chosen as CEO of the Year by The Globe and Mail's Report on Business Magazine. He is active in the community, having co-chaired the Canadian Olympic Hall of Fame Gala in Calgary as part of the Celebration of Excellence in Alberta that raised proceeds for the Canadian Olympic Foundation. He also serves as co-chair of Indspire's "Building Brighter Futures Campaign".
Michael M. Wilson(3)(4) Alberta, Canada	Director since 2014 Independent	Michael Wilson is former president and chief executive officer of Agrium Inc., a retail supplier of agricultural products and services and a wholesale producer and marketer of agricultural nutrients, which is headquartered in Calgary, a position he held from 2003 until his retirement in 2013. He previously served as executive vice president and chief operating officer. Mr. Wilson has significant experience in the petrochemical industry, serving as president of Methanex Corporation, and holding various positions with increasing responsibility in North America and Asia with Dow Chemical Company. Mr. Wilson has a bachelor's degree in chemical engineering from the University of Waterloo and currently serves on the boards of Air Canada, Celestica Inc. and Finning International Inc. He is also the chair of the Calgary Prostate Cancer Centre.

(1) Human Resources and Compensation Committee

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

(3) Audit Committee

(4) Governance Committee

Executive Officers

The following individuals are the executive officers of Suncor:

Name	Jurisdiction of Residence	Office
Steven Williams	Alberta, Canada	President and Chief Executive Officer
Alister Cowan	Alberta, Canada	Executive Vice President and Chief Financial Officer
Eric Axford	Alberta, Canada	Executive Vice President, Business Services
Mark Little	Alberta, Canada	Executive Vice President, Upstream
Mike MacSween	Alberta, Canada	Executive Vice President, Major Projects
Steve Reynish	Alberta, Canada	Executive Vice President, Strategy & Corporate Development
Kris Smith	Ontario, Canada	Executive Vice President, Downstream
Paul Gardner	Alberta, Canada	Senior Vice President, Human Resources
Janice Odegaard	Alberta, Canada	Senior Vice President, General Counsel and Corporate Secretary

As at February 22, 2016, the directors and executive officers of Suncor as a group beneficially owned, or controlled or directed, directly or indirectly, common shares of Suncor representing 0.05% of the outstanding common shares of Suncor.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

As at the date hereof, no director or executive officer of Suncor is or has been within the last ten years a director, chief executive officer or chief financial officer of a company (including Suncor) that:

(a) was the subject of a cease trade or similar order, or an order that denied the relevant company access to any exemption under securities legislation that was in effect for a period of more than 30 consecutive days while the director or executive officer was acting in that capacity; or

(b) was subject to a cease trade order or similar order, or an order that denied the relevant company access to any exemption under securities legislation that was in effect for a period of more than 30 consecutive days, that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in that capacity.

As at the date hereof, no director or executive officer of Suncor, or any of their respective personal holding companies, nor any shareholder holding a sufficient number of securities to affect materially the control of Suncor:

(a) is, or has been within the last ten years, a director or executive officer of any company (including Suncor) that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets, other than: (i) Mr. Ford, was a director of USG Corporation (until May 2014), which was in bankruptcy protection until June 2006, and who was also a director of United Airlines (until February 2006), which was in Chapter 11 bankruptcy protection until February 2006; and (ii) Mr. Benson, was a director of Winalta Inc. (Winalta) when it obtained an order on April 26, 2010 from the Alberta Court of Queen's Bench providing for creditor protection under the *Companies' Creditors Arrangement Act* (Canada). A plan of arrangement for Winalta received court confirmation later that year, and Mr. Benson ceased to be a director of Winalta in May 2013; or

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

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

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

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

AUDIT COMMITTEE INFORMATION

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

Composition of the Audit Committee

The Audit Committee is comprised of Mr. O'Brien (Chair), Ms. Côté, Mr. D'Alessandro, Ms. McCaw and Mr. Wilson. All members are independent and financially literate. The education and expertise of each member that has led to the determination of financial literacy is described in the Directors and Executive Officers section of this AIF.

For the purpose of making appointments to the company's Audit Committee, and in addition to the independence requirements, all directors nominated to the Audit Committee must meet the test of financial literacy as determined in the judgment of the Board of Directors. Also, at least one director so nominated must meet the test of financial expert as determined in the judgment of the Board of Directors. The designated financial experts on the Audit Committee are Mr. O'Brien and Mr. D'Alessandro.

Financial Literacy

Financial literacy can be generally defined as the ability to read and understand a balance sheet, an income statement and a cash flow statement. In assessing a potential appointee's level of financial literacy, the Board of Directors evaluates the totality of the individual's education and experience, including:

- the level of the person's accounting or financial education, including whether the person has earned an advanced degree in finance or accounting;
- whether the person is a professional accountant, or the equivalent, in good standing, and the length of time that the person actively has practised as a professional accountant, or the equivalent;
- whether the person is certified or otherwise identified as having accounting or financial experience by a recognized private body that establishes and administers standards in respect of such expertise, whether that person is in good standing with the recognized private body, and the length of time that the person has been actively certified or identified as having this expertise;
- whether the person has served as a principal financial officer, controller or principal accounting officer of a corporation that, at the time the person held such position, was required to file reports pursuant to securities laws and, if so, for how long;
- the person's specific duties while serving as a public accountant, auditor, principal financial officer, controller, principal accounting officer or position involving the performance of similar functions;
- the person's level of familiarity and experience with all applicable laws and regulations regarding the preparation of financial statements that must be included in reports filed under securities laws;
- the level and amount of the person's direct experience reviewing, preparing, auditing or analyzing financial statements that must be included in reports filed under provisions of securities laws;
- the person's past or current membership on one or more audit committees of companies that, at the time the person held such membership, were required to file reports pursuant to provisions of securities laws;
- the person's level of familiarity and experience with the use and analysis of financial statements of public companies; and
- whether the person has any other relevant qualifications or experience that would assist him or her in understanding and evaluating the company's financial statements and other financial information and to make knowledgeable and thorough inquiries whether the financial statements fairly present the financial condition, results of operations and cash flows of the company in accordance with generally accepted accounting principles, and whether the financial statements and other financial information, taken together, fairly present the financial condition, results of operations and cash flows of the company.

Audit Committee Financial Expert

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

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

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

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

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

(e) an understanding of audit committee functions.

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

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

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

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

(d) other relevant experience.

Audit Committee Pre-Approval Policies for Non-Audit Services

Our Audit Committee has considered whether the provision of services other than audit services is compatible with maintaining our auditors' independence and has a policy governing the provision of these services. A copy of our policy relating to Audit Committee approval of fees paid to our auditors, in compliance with the *Sarbanes-Oxley Act of 2002* and applicable Canadian law, is attached as Schedule "B" to this AIF.

Fees Paid to Auditors

Fees paid or payable to PricewaterhouseCoopers LLP, the company's auditors are as follows:

($ thousands)	2015	2014
Audit Fees	**5 823**	6 590
Audit-Related Fees	**483**	497
Tax Fees	**88**	90
All Other fees	**15**	15
Total	**6 409**	7 192

Audit Fees were paid, or are payable, for professional services rendered by the auditors for the audit of Suncor's annual financial statements, or services provided in connection with statutory and regulatory filings or engagements. Audit-Related Fees were paid for professional services rendered by the auditors for the review of quarterly financial statements and for the preparation of reports on specified procedures as they relate to audits of joint arrangements and attest services not required by statute or regulation. Tax Fees for corporate tax filings and tax planning were paid in a foreign jurisdiction where Suncor has limited activity. All Other Fees were subscriptions to auditor-provided and supported tools. All services described beside the captions "Audit Fees", "Audit-Related Fees", "Tax Fees" and "All Other Fees" were approved by the Audit Committee in compliance with paragraph (c)(7)(i) of Rule 2-01 of Regulation S-X under the *U.S. Securities and Exchange Act of 1934*, as amended (the Exchange Act). None of the fees described above were approved by the Audit Committee pursuant to paragraph (c)(7)(i)(C) of Regulation S-X under the Exchange Act.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

There are no legal proceedings in respect of which we are or were a party, or in respect of which any of our property is or was the subject during the year ended December 31, 2015, nor are there any such proceedings known by us to be contemplated, that involve a claim for damages exceeding 10% of our current assets. In addition, there have not been any (a) penalties or sanctions imposed against the company by a court relating to securities legislation or by a securities regulatory authority during the year ended December 31, 2015, (b) any other penalties or sanctions imposed by a court or regulatory body against the company that would likely be considered important to a reasonable investor in making an investment decision, or (c) settlement agreements entered into by the company before a court relating to securities legislation or with a securities regulatory authority during the year ended December 31, 2015.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

No director or executive officer, or any associate or affiliate of these persons has, or has had, any material interest, direct or indirect, in any transaction or any proposed transaction that has materially affected or is reasonably expected to materially affect Suncor within the three most recently completed financial years or during the current financial year.

TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for our common shares is Computershare Trust Company of Canada at its principal offices in Calgary, Alberta, Montreal, Quebec, Toronto, Ontario and Vancouver, British Columbia and Computershare Trust Company Inc. in Denver, Colorado.

MATERIAL CONTRACTS

During the year ended December 31, 2015, we did not enter into any contracts, nor are there any contracts still in effect, that are material to our business, other than contracts entered into in the ordinary course of business, which are not required to be filed by Section 12.2 of National Instrument 51-102 – *Continuous Disclosure Obligations*.

INTERESTS OF EXPERTS

Reserves contained in this AIF are based in part upon reports prepared by GLJ and Sproule, Suncor's independent qualified reserves evaluators. As at the date hereof, none of the partners, employees or consultants of GLJ or Sproule, respectively, as a group, through registered or beneficial interests, direct or indirect, held or are entitled to receive more than 1% of any class of our outstanding securities, including the securities of our associates and affiliates.

The company's independent auditors are PricewaterhouseCoopers LLP, Chartered Professional Accountants, who have issued an independent auditor's report dated February 24, 2016 in respect of the company's Consolidated Financial Statements, which comprise the Consolidated Balance Sheets as at December 31, 2015 and December 31, 2014 and the Consolidated Statements of Comprehensive (Loss) Income, Changes in Shareholders' Equity and Cash Flows for the years ended December 31, 2015 and December 31, 2014, and the related notes, and the report on internal control over financial reporting as at December 31, 2015. PricewaterhouseCoopers LLP has advised that they are independent with respect to the company within the meaning of the Rules of Professional Conduct of the Institute of Chartered Professional Accountants of Alberta and the rules of the United States Securities and Exchange Commission (SEC).

DISCLOSURE PURSUANT TO THE REQUIREMENTS OF THE NEW YORK STOCK EXCHANGE

As a Canadian issuer listed on the NYSE, we are not required to comply with most of the NYSE's rules and instead may comply with Canadian requirements. As a foreign private issuer, we are only required to comply with four of the NYSE's rules. These rules provide that (i) Suncor must have an audit committee that satisfies the requirements of Rule 10A-3 under the Exchange Act; (ii) the Chief Executive Officer of Suncor must promptly notify the NYSE in writing after an executive officer becomes aware of any material non-compliance with the applicable NYSE rules; (iii) Suncor must provide a brief description of any significant differences between our corporate governance practices and those followed by U.S. companies listed under the NYSE; and (iv) Suncor must provide annual, and as required, written affirmations of compliance with applicable NYSE Corporate Governance Standards.

The company has disclosed in its 2016 management proxy circular, which is available on our website at www.suncor.com, significant areas which the company does not comply with the NYSE Corporate Governance Standards. In certain instances, it is not required to obtain shareholder approval for material amendments to equity compensation plans under TSX requirements, while the NYSE requires shareholder approval of all equity compensation plans. Suncor, while in compliance with the independence requirements of applicable securities laws in Canada (specifically National Instrument 52-110 – Audit Committees) and the U.S. (specifically Rule 10A-3 of the Exchange Act), has not adopted, and is not required to adopt, the director independence standards contained in Section 303A.02 of the NYSE's Listed Company Manual, including with respect to its audit committee and compensation committee. The Board has not adopted, nor is it required to adopt, procedures to implement Section 303A.05(c)(iv) of the NYSE's Listed Company Manual in respect of compensation committee advisor independence. Except as described herein, the company is in compliance with the NYSE Corporate Governance Standards in all other significant respects.

ADDITIONAL INFORMATION

Additional information, including directors' and officers' remuneration and indebtedness, principal holders of our securities, and securities authorized for issuance under equity compensation plans, where applicable, is contained in our most recent management proxy circular for our most recent annual meeting of our shareholders that involved the election of directors. Additional financial information is provided in our 2015 audited Consolidated Financial Statements for our most recently completed financial year and in the MD&A.

Further information about Suncor, filed with Canadian securities commissions and the SEC, including periodic quarterly and annual reports and the 40-F, is available online on SEDAR at www.sedar.com and on EDGAR at www.sec.gov. In addition, our Standards of Business Conduct Code is available online at www.suncor.com. Information contained in or otherwise accessible through our website does not form part of this AIF, and is not incorporated into the AIF by reference.

ADVISORY – FORWARD-LOOKING INFORMATION AND NON-GAAP FINANCIAL MEASURES

This AIF contains certain forward-looking statements and forward-looking information (collectively, forward-looking statements) within the meaning of applicable Canadian and U.S. Securities laws and other information based on Suncor's current expectations, estimates, projections and assumptions that were made by the company in light of information available at the time the statement was made and consider Suncor's experience and its perception of historical trends, including expectations and assumptions concerning: the accuracy of reserves and resources estimates; commodity prices and interest and foreign exchange rates; capital efficiencies and cost-savings; applicable royalty rates and tax laws; future production rates; the sufficiency of budgeted capital expenditures in carrying out planned activities; the availability and cost of labour and services; and the receipt, in a timely manner, of regulatory and third-party approvals. In addition, all other statements and other information that address expectations or projections about the future, and other statements and information about Suncor's strategy for growth, expected and future expenditures or investment decisions, commodity prices, costs, schedules, production volumes, operating and financial results, future financing and capital activities, and the expected impact of future commitments are forward-looking statements. Some of the forward-looking statements and information may be identified by words like "expects", "anticipates", "will", "estimates", "plans", "scheduled", "intends", "believes", "projects", "indicates", "could", "focus", "vision", "goal", "outlook", "proposed", "target", "objective", "continue", "should", "may" and similar expressions.

Forward-looking statements in this AIF include references to:

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

- *The estimated gross oil production capacity of Hebron is 150,000 bbls/d (32,000 bbls/d net to Suncor) and that the project will include 1,200 mbbls of oil storage capacity and 52 well slots with first oil expected in 2017. At sanction, Suncor's share of the post-sanction project cost estimate was expected to be approximately $2.8 billion;*
- *Designs for the Fort Hills mining project, including the plan for 180,000 bbls/d (gross) of bitumen production capacity, the use of paraffinic froth treatment and the expectation the project will achieve first oil by the fourth quarter of 2017 and reach 90% of its planned capacity within its first year, Suncor's shares of post-sanction project costs are estimated to be $6.5 billion, and that $2.3 billion is expected to be spent on activities for the project in 2016;*
- *Preliminary designs for the Joslyn North mining project plan for 160 mbbls/d of bitumen production (gross); and*
- *TRO™ is expected to accelerate the company's tailings management processes, and is expected to be a key component of Suncor's tailings strategy. As well, under the new Tailings Management Framework issued by the AER in 2015, Suncor will begin to develop a new tailings processing technology to augment the TRO™ process.*

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

- *The company's plans to complete the next scheduled turnaround at Oil Sands Operations, specifically Upgrader 2 commencing at the end of the first quarter of 2016.*

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

- *The expectation that Suncor's wastewater treatment plant will increase the reuse and recycling of waste water from Suncor's upgrading operations and reduce freshwater withdrawal;*
- *The WTDC is expected to connect to Suncor's Firebag operations, provide an environment to test water treatment and recycling technologies and is scheduled to become operational in early 2017;*
- *Bringing the Poplar Creek assets in-house is expected to improve and enhance Suncor's overall Oil Sands operations' reliability and profitability;*
- *Suncor believes Voyageur South and Audet can be developed using mining techniques;*
- *Drilling activities, including plans for the winter 2016 In Situ drilling programs at Lewis (54 stratigraphic test wells), Meadow Creek (44 gross wells) and OSLO (five gross wells);*
- *Suncor's greenfield growth plans, starting with Meadow Creek, and its replication strategies to build standardized surface facilities, well pads and infrastructure, which are expected to reduce facility capital expenditures;*
- *Suncor's winter exploratory drilling programs are designed to identify sufficient resources to fill facilities associated with the replication strategy;*
- *Syncrude's plans to develop two mining areas adjacent to the current mine, which would consequently extend the life of Mildred Lake by approximately ten years;*
- *Project activities for Fort Hills in 2016, which are expected to focus on completing procurement for all areas except mining and completing construction in the*

ore processing plant, extraction and infrastructure areas;

- *Expectations around Suncor's new technology projects, including oxy-fuel combustion, zero liquid discharge, ESEIEH, N-SOLV™, and SAGD LITE;*
- *Expectations around exploration and appraisal initiatives in the North Sea, offshore Newfoundland and Labrador and offshore Nova Scotia, including drilling plans around these assets;*

Also:

- *Significant development activities and costs anticipated to occur or be incurred in 2016, including those identified under the Future Development Costs table in the Statement of Reserves Data and Other Oil and Gas Information section contained herein;*
- *Suncor's belief that internally generated cash flows, existing and future credit facilities, and access to debt capital markets are sufficient to fund future development costs and that interest or other funding costs on their own would not make development of any property uneconomical;*
- *Anticipated abandonment and reclamations costs;*
- *The expectation that the Aurora South mining area will not come on-stream before 2023;*
- *Suncor's plans around its reserves, including anticipated development activities for 2016 and beyond;*
- *Production estimates for 2016;*
- *Anticipated royalty and income tax rates and the impact of these rates on Suncor;*
- *Anticipated effects of environmental and climate change legislation, including Suncor's expected compliance costs; and*
- *The company's position in respect of the NOR received from the CRA (and consequentially from the Provinces of Alberta, Ontario and Quebec) regarding the income tax treatment of realized losses in 2007 on the settlement of certain derivative contracts continues to be that it will be able to successfully defend its original filing position and it will take the appropriate actions to resolve this matter. The company has provided security to the CRA and the Provinces in the approximate amount of $642 million, but the company may be required to post cash instead of security in relation to the NORs.*

Forward-looking statements and information are not guarantees of future performance and involve a number of risks and uncertainties, some that are similar to other oil and gas companies and some that are unique to Suncor. Suncor's actual results may differ materially from those expressed or implied by its forward-looking statements, so readers are cautioned not to place undue reliance on them.

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

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

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

Factors that affect our Refining and Marketing segment include, but are not limited to, fluctuations in demand and supply for refined products that impact the company's margins; market competition, including potential new market entrants; our ability to reliably operate refining and marketing facilities in order to meet production or sales targets; the possibility that completed maintenance activities may not improve operational performance or the output of related facilities; risks and uncertainties affecting construction or planned maintenance schedules, including the availability of labour and other impacts of competing projects drawing on the same resources during the same time period; and the potential for disruptions to operations and construction projects as a result of our relationships with labour unions or employee associations that represent employees at our refineries and distribution facilities.

Additional risks, uncertainties and other factors that could influence the financial and operating performance of all of Suncor's operating segments and activities include, but are not limited to, changes in general economic, market and business conditions, such as commodity prices, interest rates and currency exchange rates; fluctuations in supply and demand for Suncor's products; the successful and timely implementation of capital projects, including growth projects and regulatory projects; competitive actions of other companies, including increased competition from other oil and gas companies or from companies that provide alternative sources of energy; labour and material shortages; actions by government authorities, including the imposition or reassessment of taxes or changes to fees and royalties, such as the NORs received by Suncor from the CRA, Ontario, Alberta and Quebec relating to the settlement of certain derivative contracts, including the risk that: (i) Suncor may not be able to successfully defend its original filing position and ultimately be required to pay increased taxes, interest and penalty as a result; or (ii) Suncor may be required to post cash instead of security in relation to the NORs; changes in environmental and other regulations; the ability and willingness of parties with whom we have material relationships to perform their obligations to us; outages to third-party infrastructure that could cause disruptions to production; the occurrence of unexpected events such as fires, equipment failures and other similar events affecting Suncor or other parties whose operations or assets directly or indirectly affect Suncor; the potential for security breaches of Suncor's information systems by computer hackers or cyberterrorists, and the unavailability or failure of such systems to perform as anticipated as a result of such breaches; our ability to find new oil and gas reserves that can be developed economically; the accuracy of Suncor's reserves, resources and future production estimates; market instability affecting Suncor's ability to borrow in the capital debt markets at acceptable rates; maintaining an optimal debt to cash flow ratio; the success of the company's risk management activities using derivatives and other financial instruments; the cost of compliance with current and future environmental laws; risks and uncertainties associated with closing a transaction for the purchase or sale of an oil and gas property, including estimates of the final consideration to be paid or received, the ability of counterparties to comply with their obligations in a timely manner and the receipt of any required regulatory or other third-party approvals outside of Suncor's control that are customary to transactions of this nature; and the accuracy of cost estimates, some of which are provided at the conceptual or other preliminary stage of projects and prior to commencement or conception of the detailed engineering that is needed to reduce the margin of error and increase the level of accuracy. The foregoing important factors are not exhaustive.

Many of these risk factors and other assumptions related to Suncor's forward-looking statements and information are discussed in further detail throughout this AIF, including under the heading Risk Factors, and the company's management's discussion and analysis dated February 25, 2016 and Form 40-F on file with Canadian securities commissions at www.sedar.com and the United States Securities and Exchange Commission at www.sec.gov. Readers are also referred to the risk factors and assumptions described in other documents that Suncor files from time to time with securities regulatory authorities. Copies of these documents are available without charge from the company.

Non-GAAP Financial Measures – Oil Sands Cash Operating Costs

Oil Sands cash operating costs and cash operating costs per barrel are non-GAAP financial measures, which are calculated by adjusting Oil Sands segment operating, selling and general expense (a GAAP measure based on sales volumes) for (i) non-production costs that management believes do not relate to the production performance of Oil Sands operations, including, but not limited to, share-based compensation adjustments, costs related to the remobilization or deferral of growth projects, research, the expense recorded as part of a non-monetary arrangement involving a third-party processor, and feedstock costs for natural gas used to create hydrogen for secondary upgrading processes; (ii) revenues associated with excess capacity, including excess power generated and sold that is recorded in operating revenues; and (iii) the impacts of changes in inventory levels, such that the company is able to present cost information based on production volumes.

SCHEDULE "A"
AUDIT COMMITTEE MANDATE

The Audit Committee

The by-laws of Suncor Energy Inc. provide that the Board of Directors may establish board committees to whom certain duties may be delegated by the Board. The Board has established, among others, the Audit Committee, and has approved this mandate, which sets out the objectives, functions and responsibilities of the Audit Committee.

Objectives

The Audit Committee assists the Board of Directors by:

(a) monitoring the effectiveness and integrity of the Corporation's financial reporting systems, management information systems and internal control systems, and by monitoring financial reports and other financial matters.

(b) selecting, monitoring and reviewing the independence and effectiveness of, and where appropriate replacing, subject to shareholder approval as required by law, external auditors, and ensuring that external auditors are ultimately accountable to the Board of Directors and to the shareholders of the Corporation.

(c) reviewing the effectiveness of the internal auditors, excluding the Operations Integrity Audit department, which is specifically within the mandate of the Environment, Health & Safety Committee (references throughout this mandate to "Internal Audit" shall not include the Operations Integrity Audit department); and

(d) approving on behalf of the Board of Directors certain financial matters as delegated by the Board, including the matters outlined in this mandate.

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

Constitution

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

Functions and Responsibilities

The Audit Committee has the following functions and responsibilities:

Internal Controls

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

External and Internal Auditors

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

11. Review and approve the appointment or termination of the Head of Internal Audit, annually review a summary of the remuneration of the Head of Internal Audit, and periodically review the performance and effectiveness of the Internal Audit function including compliance with The Institute of Internal Auditors' International Professional Practices Framework for Internal Auditing.
12. Review the Internal Audit Department Charter, and the plans, activities, organizational structure and qualifications of the Internal Auditors, and monitor the department's independence.
13. Provide an open avenue of communication between management, the Internal Auditors or the external auditors, and the Board of Directors.

Financial Reporting and other Public Disclosure

14. Review the external auditor's management comment letter and management's responses thereto, and inquire as to any disagreements between management and external auditors or restrictions imposed by management on external auditors. Review any unadjusted differences brought to the attention of management by the external auditor and the resolution thereof.
15. Review with management and the external auditors the financial materials and other disclosure documents referred to in paragraph 16, including any significant financial reporting issues, the presentation and impact of significant risks and uncertainties, and key estimates and judgements of management that may be material to financial reporting including alternative treatments and their impacts.
16. Review and approve the Corporation's interim consolidated financial statements and accompanying management's discussion and analysis ("MD&A"). Review and make recommendations to the Board of Directors on approval of the Corporation's annual audited financial statements and MD&A, Annual Information Form and Form 40-F. Review other material annual and quarterly disclosure documents or regulatory filings containing or accompanying audited or unaudited financial information.
17. Authorize any changes to the categories of documents and information requiring audit committee review or approval prior to external disclosure, as set out in the Corporation's policy on external communication and disclosure of material information.
18. Review any change in the Corporation's accounting policies.
19. Review with legal counsel any legal matters having a significant impact on the financial reports.

Oil and Gas Reserves

20. Review with reasonable frequency Suncor's procedures for:
    (a) the disclosure, in accordance with applicable law, of information with respect to Suncor's oil and gas activities, including procedures for complying with applicable disclosure requirements;
    (b) providing information to the qualified reserves evaluators ("Evaluators") engaged annually by Suncor to evaluate Suncor's reserves data for the purpose of public disclosure of such data in accordance with applicable law.
21. Annually approve the appointment and terms of engagement of the Evaluators, including the qualifications and independence of the Evaluators; review and approve any proposed change in the appointment of the Evaluators, and the reasons for such proposed change including whether there have been disputes between the Evaluators and management.
22. Annually review Suncor's reserves data and the report of the Evaluators thereon; annually review and make recommendations to the Board of Directors on the approval of (i) the content and filing by the Company of a statement of reserves data ("Statement") and the report thereon of management and the directors to be included in or filed with the Statement, and (ii) the filing of the report of the Evaluators to be included in or filed with the Statement, all in accordance with applicable law.

Risk Management

23. Periodically review the policies and practices of the Corporation respecting cash management, financial derivatives, financing, credit, insurance, taxation, commodities trading and related matters. Oversee the Board's risk management governance model by conducting periodic reviews with the objective of appropriately reflecting the principal risks of the Corporation's business in the mandate of the Board and its committees. Conduct periodic review of and provide oversight on the specific Suncor Principal Risks which have been delegated to the Committee for oversight.

Pension Plan

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

Security

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

Other Matters

26. Conduct any independent investigations into any matters which come under its scope of responsibilities.
27. Review any recommended appointees to the office of Chief Financial Officer.
28. Review and/or approve other financial matters delegated specifically to it by the Board of Directors.

Reporting to the Board

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

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

SCHEDULE "B" – SUNCOR ENERGY INC. POLICY AND PROCEDURES FOR PRE-APPROVAL OF AUDIT AND NON-AUDIT SERVICES

Pursuant to the Sarbanes-Oxley Act of 2002 and Multilateral Instrument 52-110, the Securities and Exchange Commission and the Ontario Securities Commission respectively has adopted final rules relating to audit committees and auditor independence. These rules require the Audit Committee of Suncor Energy Inc ("Suncor") to be responsible for the appointment, compensation, retention and oversight of the work of its independent auditor. The Audit Committee must also pre-approve any audit and non-audit services performed by the independent auditor or such services must be entered into pursuant to pre-approval policies and procedures established by the Audit Committee pursuant to this policy.

I. Statement of Policy

The Audit Committee has adopted this Policy and Procedures for Pre-Approval of Audit and Non-Audit Services (the "Policy"), which sets forth the procedures and the conditions pursuant to which services proposed to be performed by the independent auditor will be pre-approved. The procedures outlined in this Policy are applicable to all Audit, Audit-Related, Tax Services and All Other Services provided by the independent auditor.

II. Responsibility

Responsibility for the implementation of this Policy rests with the Audit Committee. The Audit Committee delegates its responsibility for administration of this policy to management. The Audit Committee shall not delegate its responsibilities to pre-approve services performed by the independent auditor to management.

III. Definitions

For the purpose of these policies and procedures and any pre-approvals:

(a) "Audit services" include services that are a necessary part of the annual audit process and any activity that is a necessary procedure used by the auditor in reaching an opinion on the financial statements as is required under generally accepted auditing standards ("GAAS"), including technical reviews to reach audit judgement on accounting standards;

The term "audit services" is broader than those services strictly required to perform an audit pursuant to GAAS and include such services as:

(i) the issuance of comfort letters and consents in connections with offerings of securities;

(ii) the performance of domestic and foreign statutory audits;

(iii) Attest services required by statute or regulation;

(iv) Internal control reviews; and

(v) Assistance with and review of documents filed with the Canadian Securities administrators, the Securities and Exchange Commission and other regulators having jurisdiction over Suncor and its subsidiaries, and responding to comments from such regulators;

(b) "Audit-related services" are assurance (e.g. due diligence services) and related services traditionally performed by the external auditors and that are reasonably related to the performance of the audit or review of financial statements and not categorized under "audit fees" for disclosure purposes.

"Audit-related services" include:

(i) employee benefit plan audits, including audits of employee pension plans;

(ii) due diligence related to mergers and acquisitions;

(iii) consultations and audits in connection with acquisitions, including evaluating the accounting treatment for proposed transactions;

(iv) internal control reviews;

(v) attest services not required by statute or regulation; and

(vi) consultations regarding financial accounting and reporting standards.

Non-financial operational audits are **not** "audit-related" services.

(c) "Tax services" include, but are not limited to, services related to the preparation of corporate and/or personal tax filings, tax due diligence as it pertains to mergers, acquisitions and/or divestitures, and tax planning;

(d) "All other services" consist of any other work that is neither an Audit service, nor an Audit-Related service nor a Tax service, the provision of which by the independent auditor is not expressly prohibited by Rule 2-01(c)(7) of Regulation S-X under the Securities and Exchange Act of1934, as amended.
(See Appendix A for a summary of the prohibited services.)

IV. General Policy

The following general policy applies to all services provided by the independent auditor.

- All services to be provided by the independent auditor will require specific pre-approval by the Audit Committee. The Audit Committee will not approve engaging the independent auditor for services which can reasonably be classified as "tax services" or "all other services" unless a compelling business case can be made for retaining the independent auditor instead of another service provider.
- The Audit Committee will not provide pre-approval for services to be provided in excess of twelve months from the date of the pre-approval, unless the Audit Committee specifically provides for a different period.
- The Audit Committee has delegated authority to pre-approve services with an estimated cost not exceeding $100,000 in accordance with this Policy to the Chairman of the Audit Committee. The delegate member of the Audit Committee must report any pre-approval decision to the Audit Committee at its next meeting.
- The Chairman of the Audit Committee may delegate his authority to pre-approve services to another sitting member of the Audit Committee provided that the recipient has also been delegated the authority to act as Chairman of the Audit Committee in the Chairman's absence. A resolution of the Audit Committee is required to evidence the Chairman's delegation of authority to another Audit Committee member under this policy.
- The Audit Committee will, from time to time, but no less than annually, review and pre-approve the services that may be provided by the independent auditor.
- The Audit Committee must establish pre-approval fee levels for services provided by the independent auditor on an annual basis. On at least a quarterly basis, the Audit Committee will be provided with a detailed summary of fees paid to the independent auditor and the nature of the services provided, and a forecast of fees and services that are expected to be provided during the remainder of the fiscal year.
- The Audit Committee will **not** approve engaging the independent auditor to provide any prohibited non-audit services as set forth in Appendix A.
- The Audit Committee shall evidence their pre-approval for services to be provided by the independent auditor as follows:
  - (a) In situations where the Chairman of the Audit Committee pre-approves work under his delegation of authority, the Chairman will evidence his pre-approval by signing and dating the pre-approval request form, attached as Appendix B. If it is not practicable for the Chairman to complete the form and transmit it to the Company prior to engagement of the independent audit, the Chairman may provide verbal or email approval of the engagement, followed up by completion of the request form at the first practical opportunity.
  - (b) In all other situations, a resolution of the Audit Committee is required.
- All audit and non-audit services to be provided by the independent auditors shall be provided pursuant to an engagement letter that shall:
  - (a) be in writing and signed by the auditors;
  - (b) specify the particular services to be provided;
  - (c) specify the period in which the services will be performed;
  - (d) specify the estimated total fees to be paid, which shall not exceed the estimated total fees approved by the Audit Committee pursuant to these procedures, prior to application of the 10% overrun;
  - (e) include a confirmation by the auditors that the services are not within a category of services the provision of which would impair their independence under applicable law and Canadian and U.S. generally accepted accounting standards.
- The Audit Committee pre-approval permits an overrun of fees pertaining to a particular engagement of no greater than 10% of the estimate identified in the associated engagement letter. The intent of the overrun authorization is to ensure on an interim basis only, that services can continue pending a review of the fee estimate, and, if required, further Audit Committee approval of the overrun. If an overrun is expected to exceed the 10% threshold, as soon as the overrun is identified, the Audit Committee or its designate must be notified and an additional pre-approval obtained prior to the engagement continuing.

V. Responsibilities of External Auditors

To support the independence process, the independent auditors will:

(a) Confirm in each engagement letter that performance of the work will not impair independence;

(b) Satisfy the Audit Committee that they have in place comprehensive internal policies and processes to ensure adherence, world-wide, to independence requirements, including robust monitoring and communications;

(c) Provide communication and confirmation to the Audit Committee regarding independence on at least a quarterly basis;

(d) Maintain registration by the Canadian Public Accountability Board and the U.S. Public Company Accounting Oversight Board; and

(e) Review their partner rotation plan and advise the Audit Committee on an annual basis.

In addition, the external auditors will:

(f) Provide regular, detailed fee reporting including balances in the "Work in Progress" account;

(g) Monitor fees and notify the Audit Committee as soon as a potential overrun is identified.

VI. Disclosures

Suncor will, as required by applicable law, annually disclose its pre-approval policies and procedures, and will provide the required disclosure concerning the amounts of audit fees, audit-related fees, tax fees and all other fees paid to its outside auditors in its filings with the SEC.

Approved and Accepted April 28, 2004

Appendix A – Prohibited Non-Audit Services

An external auditor is not independent if, at any point during the audit and professional engagement period, the auditor provides the following non-audit services to an audit client.

Bookkeeping or other services related to the accounting records or financial statements of the audit client. Any service, unless it is reasonable to conclude that the results of these services will not be subject to audit procedures during an audit of Suncor's financial statements, including:

- Maintaining or preparing the audit client's accounting records;
- Preparing Suncor's financial statements that are filed with the SEC or that form the basis of financial statements filed with the SEC; or
- Preparing or originating source data underlying Suncor's financial statements.

Financial information systems design and implementation. Any service, unless it is reasonable to conclude that the results of these services will not be subject to audit procedures during an audit of Suncor's financial statements, including:

- Directly or indirectly operating, or supervising the operation of, Suncor's information systems or managing Suncor's local area network; or
- Designing or implementing a hardware or software system that aggregates source data underlying the financial statements or generates information that is significant to Suncor's financial statements or other financial information systems taken as a whole.

Appraisal or valuation services, fairness opinions or contribution-in-kind reports. Any appraisal service, valuation service or any service involving a fairness opinion or contribution-in-kind report for Suncor, unless it is reasonable to conclude that the results of these services will not be subject to audit procedures during an audit of Suncor's financial statements.

Actuarial services. Any actuarially-oriented advisory service involving the determination of amounts recorded in the financial statements and related accounts for Suncor other than assisting Suncor in understanding the methods, models, assumptions, and inputs used in computing an amount, unless it is reasonable to conclude that the results of these services will not be subject to audit procedures during an audit of Suncor's financial statements.

Internal audit outsourcing services. Any internal audit service that has been outsourced by Suncor that relates to Suncor's internal accounting controls, financial systems or financial statements, unless it is reasonable to conclude that the result of these services will not be subject to audit procedures during an audit of Suncor's financial statements.

Management functions. Acting, temporarily or permanently, as a director, officer, or employee of Suncor, or performing any decision-making, supervisory, or ongoing monitoring function for Suncor.

Human resources. Any of the following:

- Searching for or seeking out prospective candidates for managerial, executive, or director positions;
- Engaging in psychological testing, or other formal testing or evaluation programs;
- Undertaking reference checks of prospective candidates for an executive or director position;
- Acting as a negotiator on Suncor's behalf, such as determining position, status or title, compensation, fringe benefits, or other conditions of employment; or
- Recommending, or advising Suncor to hire a specific candidate for a specific job (except that an accounting firm may, upon request by Suncor, interview candidates and advise Suncor on the candidate's competence for financial accounting, administrative, or control positions).

Broker-dealer, investment adviser or investment banking services. Acting as a broker-dealer (registered or unregistered), promoter, or underwriter, on behalf of Suncor, making investment decisions on behalf of Suncor or otherwise having discretionary authority over Suncor's investments, executing a transaction to buy or sell Suncor's investment, or having custody of Suncor's assets, such as taking temporary possession of securities purchased by Suncor.

Legal services. Providing any service to Suncor that, under circumstances in which the service is provided, could be provided only by someone licensed, admitted, or otherwise qualified to practice law in the jurisdiction in which the service is prohibited.

Expert services unrelated to the audit. Providing an expert opinion or other expert service for Suncor, or Suncor's legal representative, for the purpose of advocating Suncor's interest in litigation or in a regulatory or administrative proceeding or investigation. In any litigation or regulatory or administrative proceeding or investigation, an accountant's independence shall not be deemed to be impaired if the accountant provides factual accounts, including testimony, of work performed or explains the positions taken or conclusions reached during the performance of any service provided by the accountant for Suncor.

Appendix B – Pre-Approval Request Form

NATURE OF WORK	ESTIMATED FEES (Cdn$)
Total	

Date

Signature

SCHEDULE "C" – FORM 51-101F2 REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

To the board of directors of Suncor Energy Inc. (the "Company"):

1. We have evaluated the Company's reserves data as at December 31, 2015. The reserves data are estimates of proved reserves and probable reserves and related future net revenues as at December 31, 2015, estimated using forecast prices and costs.
2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.
3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the "COGE Handbook") maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).
4. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.
5. The following table shows the net present value of future net revenues (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated for the year ended December 31, 2015, and identifies the respective portions thereof that we have evaluated and reported on to the Company's management and board of directors:

Independent Qualified Reserves Evaluator	Effective Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenues (before income taxes, 10% discount rate, $ millions)			
			Audited	Evaluated	Reviewed	Total
GLJ Petroleum Consultants Ltd.	Oil Sands In Situ December 31, 2015	Canada	—	21 064	—	21 064
GLJ Petroleum Consultants Ltd.	Oil Sands Mining December 31, 2015	Canada	—	14 891	—	14 891
			—	35 955	—	35 955

6. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.
7. We have no responsibility to update our reports referred to in paragraph 5 for events and circumstances occurring after the effective date of our reports.
8. Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

EXECUTED as to our report referred to above:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, February 25, 2016

"Caralyn P. Bennett"

Caralyn P. Bennett, P.Eng.
Vice-President

SCHEDULE "D" – FORM 51-101F2 REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

To the board of directors of Suncor Energy Inc. (the "Company"):

1. We have evaluated the Company's reserves data as at December 31, 2015. The reserves data are estimates of proved reserves and probable reserves and related future net revenues as at December 31, 2015, estimated using forecast prices and costs.
2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.
3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the "COGE Handbook") maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).
4. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.
5. The following table shows the net present value of future net revenues (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated for the year ended December 31, 2015, and identifies the respective portions thereof that we have evaluated and reported on to the Company's management and board of directors:

Independent Qualified Reserves Evaluator	Effective Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenues (before income taxes, 10% discount rate, $ millions)			
			Audited	Evaluated	Reviewed	Total
Sproule Associates Limited	East Coast Canada December 31, 2015	Newfoundland Offshore, Canada	—	6 407	—	6 407
Sproule Associates Limited	North America Onshore December 31, 2015	Western Canada	—	35	—	35
Sproule International Limited	North Sea December 31, 2015	North Sea, United Kingdom	—	3 073	—	3 073
Sproule International Limited	Other International December 31, 2015	Libya	—	1 879	—	1 879
			—	11 394	—	11 394

6. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.
7. We have no responsibility to update our reports referred to in paragraph 5 for events and circumstances occurring after the effective date of our reports.
8. Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

EXECUTED as to our report referred to above:

Sproule Associates Limited and Sproule International Limited, Calgary, Alberta, Canada, February 25, 2016

"Harry J. Helwerda"

Harry J. Helwerda, P.Eng., FEC, FGC (Hon.)
President and Director

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

Management of Suncor Energy Inc. (the "Company") are responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data.

Independent qualified reserves evaluators have evaluated the Company's reserves data. The reports of the independent qualified reserves evaluators will be filed with securities regulatory authorities concurrently with this report.

The Audit Committee of the board of directors of the Company has:

(a) reviewed the Company's procedures for providing information to the independent qualified reserves evaluators;

(b) met with the independent qualified reserves evaluators to determine whether any restrictions affected the ability of the independent qualified reserves evaluators to report without reservation; and

(c) reviewed the reserves data with management and the independent qualified reserves evaluators.

The Audit Committee of the board of directors has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has, on the recommendation of the Audit Committee, approved:

(a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data and other oil and gas information;

(b) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluators on the reserves data; and

(c) the content and filing of this report.

Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

"*Steven W. Williams*"

STEVEN W. WILLIAMS
President and Chief Executive Officer

"*Alister Cowan*"

ALISTER COWAN
Executive Vice President and Chief Financial Officer

"*James Simpson*"

JAMES SIMPSON
Chair of the Board of Directors

"*Michael W. O'Brien*"

MICHAEL W. O'BRIEN
Chair of the Audit Committee

February 25, 2016

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