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SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 40-F

(Check One)

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

or

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

For fiscal year ended: December 31, 2016
Commission File Number: No. 1-12384

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

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

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

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

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

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

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

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

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

None

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

None

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

ý Annual Information Form ý Annual Audited Financial Statements

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

Common Shares	**As of December 31, 2016 there were 1,667,913,629 Common Shares issued and outstanding**

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

Yes ý No o

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

Yes o No o

INCORPORATION BY REFERENCE

This annual report on Form 40-F is incorporated by reference into and as an exhibit to, as applicable, each of the following Registration Statements of the Registrant under the Securities Act of 1933: Form S-8 (File No. 333-87604), Form S-8 (File No. 333-112234), Form S-8 (File No. 333-118648), Form S-8 (File No. 333-124415), Form S-8 (File No. 333-149532), Form S-8 (File No. 333-161021) and Form S-8 (File No. 333-161029). The Registrant's Annual Information Form dated March 1, 2017, included in this annual report on Form 40-F, and Audited Consolidated Financial Statements and Management's Discussion and Analysis for the year ended December 31, 2016, included as Exhibit 99-1 and Exhibit 99-2, respectively, to this annual report on Form 40-F, are incorporated by reference into and as an exhibit to, as applicable, the Registrant's Registration Statement on Form F-10 (File No. 333-212212).

SUNCOR ENERGY INC.

ANNUAL INFORMATION FORM

Dated March 1, 2017

ANNUAL INFORMATION FORM DATED MARCH 1, 2017

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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 2016 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, 2016. References to our MD&A mean Suncor's Management's Discussion and Analysis, dated March 1, 2017.

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 this 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 10.0 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 and may contain sulphur or other elements or compounds. 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 porous and permeable subsurface rock unit that contains a separate accumulation of petroleum that is confined by impermeable rock or water barriers and is characterized by a single pressure system.

Wells

> **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 excess fluids from operations can be safely injected for safe disposal. These wells are operated within limits approved by the appropriate regulatory bodies.
>
> **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 may include fluid saturations, temperature or 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 purpose of injecting gas, steam or water.

Stratigraphic test 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.

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

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 products for the company's downstream operations.

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_2	carbon dioxide
CO_{2e}	carbon dioxide equivalent
m^3	cubic metres
m^3/d	cubic metres per day
km	kilometres
MW	Megawatts
Mt	Megatonnes

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

Suncor converts certain natural gas volumes to boe, boe/d, mboe, mboe/d and 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 tonne = 0.984 tons (long)
1 m^3 natural gas = 35.49 cubic feet	1 tonne = 1.102 tons (short)

1 m^3 overburden = 1.31 cubic yards	1 kilometre = 0.62 miles
	1 hectare = 2.5 acres

(1) Conversion using the above factors on rounded numbers appearing in this AIF may produce small differences from reported amounts 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." On January 1, 2017, Suncor amalgamated with certain of its wholly owned subsidiaries under the CBCA.

Suncor's registered and head office is located at 150 – 6 th Avenue S.W., Calgary, Alberta, T2P 3E3.

Intercorporate Relationships

Material subsidiaries, each of which was owned 100%, directly or indirectly, by the company as at December 31, 2016, are as follows:

Name	Jurisdiction Where Organized	Description
Canadian operations		
Suncor Energy Oil Sands Limited Partnership	Alberta	This partnership holds most of the company's oil sands operations assets.
Suncor Energy Products Inc.	Canada	This subsidiary held interests in the company's energy marketing and renewable energy businesses.(1)
Suncor Energy Products Partnership	Alberta	This partnership holds substantially all of the company's Canadian refining and marketing assets.
Suncor Energy Marketing Inc.	Alberta	Through this subsidiary, production from our upstream Canadian businesses is marketed. This subsidiary also administers Suncor's energy trading and power activities, markets certain third-party products, procures crude oil feedstock and natural gas for our downstream business, and procures and markets NGLs and LPG for our downstream business.
Suncor Energy Ventures Holding Corporation	Alberta	A subsidiary which indirectly owned a 36.74% ownership in the Syncrude joint operation previously owned by Canadian Oil Sands Limited (COS).(2)
Suncor Energy Ventures Partnership	Alberta	A subsidiary which owns a 17% ownership in the Syncrude joint operation.
U.S. operations		
Suncor Energy (U.S.A.) Marketing Inc.	Delaware	A subsidiary that procures and markets third-party crude oil, in addition to procuring crude oil feedstock for the company's refining operations.
Suncor Energy (U.S.A.) Inc.	Delaware	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.

(1) This subsidiary amalgamated into Suncor Energy Inc. on January 1, 2017.

(2) This subsidiary amalgamated into Suncor Energy Ventures Corporation on January 1, 2017.

The company's remaining subsidiaries each accounted for (i) less than 10% of the company's consolidated assets as at December 31, 2016, and (ii) less than 10% of the company's consolidated operating revenues for the fiscal year ended December 31, 2016. In aggregate, the remaining subsidiaries accounted for less than 20% of each of the company's consolidated assets as at December 31, 2016 and the company's consolidated operating revenues for the fiscal year ended December 31, 2016.

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. We also conduct energy trading activities focused principally on the marketing and trading of crude oil, natural gas, power and byproducts. We also operate a renewable energy business as part of our overall portfolio of assets.

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 is comprised of:

- **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 such as Suncor's East Tank Farm (ETF) operations. In Situ production is either upgraded by Oil Sands Base, or blended with diluent and marketed directly to customers. The ETF facility is currently being expanded to blend planned Fort Hills bitumen production for Suncor and the other Fort Hills project partners. Suncor has entered into participation agreements with the Fort McKay First Nation and Mikisew Cree First Nation for the sale of a combined 49% interest in the new terminal assets once they are placed in service.

- **Oil Sands venture** operations include Suncor's 50.8% interest in the Fort Hills mining project, where Suncor is the operator, and its 53.74% working interest in the Syncrude oil sands mining and upgrading joint operation. The company's interest in Syncrude increased from 12% as a result of the acquisition of COS, and the purchase of an additional 5% interest from Murphy Oil Company Ltd. (Murphy) during 2016. Suncor also holds a 36.75% interest in the idled Joslyn North mining prospect.

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 non-operated interests in Hibernia (20% in the base project and 19.132% in the Hibernia Southern Extension Unit (HSEU)), White Rose (27.5% in the base project and 26.125% in the extensions), and the Hebron project (21.034%). 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 non-operated interests in Buzzard (29.89%), Golden Eagle Area Development (GEAD) (26.69%), the Rosebank future development project acquired in 2016 (30%) and the Oda project (30%). The first three projects are located in the U.K. sector of the North Sea, while the Oda project (previously known as the Butch discovery) is located in the southern part of the Norwegian North Sea. 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 through the majority of 2016 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, and the company believes the assets in both Libya and Syria have sustained various degrees of damage over the past several years, including certain assets that have sustained significant damage.

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 and a refinery located in Sarnia, Ontario. Suncor previously operated a lubricants business located in Mississauga, Ontario that manufactured and blended products which were marketed worldwide. During 2016, Suncor entered into an agreement to sell its lubricants business, and the sale closed on February 1, 2017.

    - **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 in Montreal, Quebec, product pipelines and terminals in Canada and the U.S. and the St. Clair ethanol plant in Ontario.

- **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.

CORPORATE, ENERGY TRADING AND ELIMINATIONS

The grouping **Corporate, Energy Trading and Eliminations** includes the company's investments in renewable energy projects, results related to energy marketing, supply and trading activities, and other activities not directly attributable to any other operating segment.

- **Renewable Energy** investment activities include development, construction, and ownership of Suncor-operated and joint venture partner-operated renewable power facilities across Canada. This includes a portfolio of operating wind power facilities located in Alberta, Saskatchewan and Ontario, as well as a portfolio of optioned lands for future wind and solar power project development. In December 2016, Suncor entered into an agreement to sell its 50% share of the Cedar Point wind facility in Ontario. The transaction closed on January 24, 2017.

- **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 **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.

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.

- **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 GEAD.** First oil was achieved at the Golden Eagle project late in 2014, which ramped up to its planned 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 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 and this declaration remains in effect.

- **Firebag production exceeded 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 Canada Ltd. (Total E&P) and now owns 50.8% of the project.

- **Upgrader utilization exceeded 90%.** Suncor's long-term commitment to operational excellence continued to drive operational efficiencies, including increased upgrader reliability in 2015.

- **Fort Hills construction ramped up with substantial completion of detailed engineering work.** Construction continued to ramp up with more than 50% of construction completed at the end of 2015. First oil is expected in late 2017.

- **Firebag nameplate capacity increased from 180,000 bbls/d to 203,000 bbls/d.** Cost-effective debottlenecking activities were completed at Firebag, with sustained production levels in excess of 180,000 bbls/d achieved in 2015. This resulted in a nameplate capacity increase effective January 1, 2016.

- **Completion of asset exchange and lease with TransAlta Corporation.** 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 has improved Suncor's overall Oil Sands operations' 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 included 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, with a focus on technology and innovation, sets the ambition for managing 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.

2016

- **Acquisition of COS.** In the first quarter of 2016, Suncor acquired COS, which owned 36.74% of Syncrude. This acquisition has provided Suncor with an incremental 128,600 bbls/d of SCO production capacity through its additional ownership interest in Syncrude.

- **Acquisition of additional 5% interest in Syncrude.** In June 2016, Suncor acquired an additional 5% interest in Syncrude from Murphy, which added a further 17,500 bbls/d of SCO capacity. Suncor now owns a 53.74% working interest in Syncrude.

- **Completed a turnaround of the Upgrader 2 facilities.** The first full turnaround of the Upgrader 2 facilities was completed since the company moved to a five-year cycle.

- **Executed an equity offering for net proceeds of $2.8 billion.** The net proceeds were used to fund the acquisition of the additional 5% interest in Syncrude from Murphy and to reduce debt to provide ongoing balance sheet flexibility.

- **Oil Sands operations production returned safely to normal operating rates.** Suncor's Oil Sands production, including Syncrude, was completely shut in during the forest fires in the Fort McMurray region. Suncor leveraged its capability to safely evacuate community members and workers from the region. No assets were damaged during the forest fires and operations subsequently returned to normal production rates by mid-July.

- **Purchased 30% participating interest in the Rosebank project.** The Rosebank project is considered one of the largest remaining undeveloped resources in the U.K. North Sea. The project is expected to be complementary to Suncor's existing U.K. portfolio.

- **Sale of equity interest in Suncor's ETF development.** The company announced the signing of participation agreements for the sale of a 34.3% equity interest in Suncor's ETF development to Fort McKay First Nation on September 6, 2016 and a further 14.7% equity interest to Mikisew Cree First Nation on October 17, 2016. These transactions are expected to close in the third quarter of 2017.

- **Sale of Petro-Canada Lubricants Inc. (PCLI) business.** In October 2016, the company announced that it had reached an agreement to sell PCLI for gross proceeds of $1.125 billion (subject to customary post-closing adjustments) to a subsidiary of HollyFrontier Corporation (HollyFrontier). The transaction closed on February 1, 2017 and included PCLI's production and manufacturing facilities in Mississauga, Ontario as well as the global marketing and distribution assets held by PCLI. The sale of PCLI reinforces the company's commitment to continuously optimize its asset portfolio and focus on core assets.

- **Suncor reached an agreement for the sale of its interest in the Cedar Point wind facility.** In December 2016, an agreement was signed for the sale of Suncor's 50% share of Cedar Point, which closed on January 24, 2017 for gross proceeds of $291 million.

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 that require units to be taken offline to be completed are often referred to as turnarounds. Turnaround maintenance provides opportunities for both preventive maintenance and capital replacement, which are expected to improve reliability and operational efficiency. Planned maintenance events generally occur on routine cycles, determined by historical operating performance, recommended usage factors or regulatory requirements. A turnaround typically involves shutting down the unit, inspecting it for wear or other damage, repairing or replacing components, and then restarting the unit. Operations may be impacted during these activities.

- **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.

  Oil sands tailings are the remaining sand, water, clay, silt and residual hydrocarbons left after the majority of hydrocarbons are extracted from the ore during the water-based bitumen extraction process. Suncor submitted an updated tailings management plan that is requesting an increase in treatment capacity within the current tailings management approach (TRO™) at the company's Oil Sands Base Plant. This approach aligns with the Government of Alberta's Tailings Management Framework (TMF) and the Alberta Energy Regulator's (AER) Directive 085 – Fluid Tailings Management for Oil Sands Mining Projects (the Tailings Directive).

Oil Sands Base Assets

Millennium and North Steepbank

Suncor pioneered the commercial development of the Athabasca oil sands beginning in 1962, achieving first production in 1967; 2017 marks Suncor's 50th anniversary of producing oil from the Athabasca oil sands. Bitumen is currently mined from the Millennium area, which began production in 2001, and the North Steepbank area, which began production in 2011. During 2016, the company mined approximately 129 million tonnes of bitumen ore (2015 – 168 million tonnes) and processed an average of 238 mbbls/d of mined bitumen in its extraction facilities (2015 – 307 mbbls/d). Due to the forest fires that occurred in the second quarter of 2016, production was shut in and, therefore, did not reach full production capacity throughout 2016.

Upgrading facilities

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. 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 2016, Suncor averaged 259 mbbls/d of upgraded (SCO and diesel) production net of the company's internal consumption (2015 – 320 mbbls/d) sourced from bitumen provided by both Oil Sands Base and In Situ operations. Due to the forest fires that occurred in the second quarter of 2016, the upgrader units did not produce to full capacity throughout 2016.

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 fuelled 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 to facilitate future well drilling.

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 capacity of 203 mbbls/d. The capacity was increased from 180 mbbls/d to 203 mbbls/d, effective January 1, 2016, as a result of debottlenecking 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, 2016, Firebag had 12 well pads in operation, with 154 SAGD well pairs and 38 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 85 MW, and in 2016 Firebag exported approximately 215 MW of electricity to the Alberta power grid and Oil Sands Base Plant. Due to the forest fires that occurred in the second quarter of 2016, the cogeneration units did not produce to full capacity throughout 2016. There are also 13 OTSGs at the site for additional steam generation.

During 2016, Firebag production averaged 181 mbbls/d (2015 – 187 mbbls/d) with a SOR of 2.6 (2015 – 2.6).

MacKay River

Production from Suncor's MacKay River operations commenced in 2002. As at December 31, 2016, MacKay River included seven well pads with 108 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 generates steam and electricity. There are also four OTSGs at the site for additional steam generation. Due to the forest fires that occurred in the second quarter of 2016, the central processing facilities did not produce to full capacity throughout 2016.

During 2016, MacKay River production averaged 28 mbbls/d (2015 – 31 mbbls/d) with a SOR of 3.2 (2015 – 2.9).

Suncor has regulatory approval to increase bitumen processing capacity by approximately 20 mbbls/d with an additional central processing facility at MacKay River.

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, Chard, and a non-operated interest in Kirby on which it may undertake exploratory or delineation drilling. Suncor holds a 100% working interest in Lewis, a 75% working interest in Meadow Creek, a 77.78% working interest in OSLO, interests varying from 25% to 50% in Chard and a 10% working interest in Kirby. In 2016, Suncor drilled 54 stratigraphic test wells at Lewis; 44 gross stratigraphic test wells and two service wells at Meadow Creek; five gross stratigraphic test wells at OSLO (which is adjacent to Lewis); and no drilling occurred at Kirby in 2016. Suncor does not have plans for winter 2017 drilling at Lewis, OSLO and Meadow Creek.

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.

Oil Sands Ventures

Syncrude

Suncor holds a 53.74% interest in the Syncrude joint operation with gross bitumen conversion capacity of 350 mbbls/d (188 mbbls/d net to Suncor) to intermediate sour SCO. The company's interest in Syncrude increased in 2016 from 12% as a result of the acquisition of COS (which held a 36.74% interest in Syncrude), and the purchase of an additional 5% interest in the joint operation from Murphy. Syncrude began producing in 1978 and is operated by Syncrude Canada Ltd. (SCL). In 2006, SCL entered into a management services agreement with Imperial Oil Resources (Imperial Oil) to provide business services and leadership. The project is located near Fort McMurray and includes mining operations at Mildred Lake North and Aurora North. 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 a minimum of 10 years. The plan proposes to use existing mining and extraction facilities. Regulatory applications for these areas were submitted in December 2014.

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 2016, Suncor's share of Syncrude production averaged 130 mbbls/d (2015 – 30 mbbls/d). Due to the forest fires that occurred in the second quarter of 2016, Syncrude did not produce to full capacity throughout 2016. Sustaining capital expenditures in 2017 for Syncrude are expected to focus on planned maintenance.

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. Fort Hills will use a paraffinic froth treatment process to produce a marketable bitumen product which partially decarbonizes the oil and returns approximately 70% of the barrel, which has the highest carbon content, to the mine. 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. Designs for the Fort Hills mining project were updated during 2016, resulting in an

increase in nameplate capacity to 194 mbbls/d (gross) of bitumen (99 mbbls/d net to Suncor).

Suncor holds a 50.8% working interest in Fort Hills and is the operator of the project. The company's share of the project costs is estimated to be $8.1 – $8.3 billion, including the impacts of changes in the Canadian dollar since the project was sanctioned. Suncor's share of Fort Hills' remaining project capital is between $1.6 and $1.8 billion. The majority of the spend will occur in 2017 and will be completed within Suncor's existing capital guidance range. Project activities in 2017 will focus on final construction completion of utilities, the first train of secondary extraction and release of these project areas to operations. Activities will also include progress towards the remaining two trains of secondary extraction expected to be turned over in 2018 as originally planned.

As at December 31, 2016, Suncor had incurred $6.5 billion in project costs with completion of the module program. Installation of all major modules and all major equipment has been completed in both of the two remaining major construction areas, utilities and secondary extraction. Construction in these areas has achieved peak activity and continues to focus on productivity and achieving critical milestones for delivery of first oil per the target schedule. All other major project areas, mining, ore processing, site infrastructure, and extraction and tailings are in various stages of final construction completion, commissioning/start-up, and release to operations. Construction was 76% complete at December 31, 2016 and is now fully site-based. First oil continues to remain on track for late 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 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.

In 2016, Suncor proved commercial viability of the following technologies:

- Next Generation In Situ – Suncor has developed a commercial replication model based on SAGD and solvent/chemical co-injection. Significant reductions in overall footprint and equipment were achieved by implementing a new well pad facilities model incorporating cogeneration at approximately 85 MW per phase and operations with remote control. This model is expected to contribute to lower capital intensity and operating costs.

- Permanent Aquatic Storage Structure (PASS) – The PASS technology will treat fluid fine tailings such that fine tailings will settle more quickly and residual bitumen will be permanently immobilized. The treated tailings will be deposited in an end of mine life pit which will be water capped to form a lake. This is expected to result in a lake capable of supporting a vibrant aquatic ecosystem.

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

- Autonomous Haulage System (AHS) – Suncor is testing haul trucks that operate within an Autonomous Haulage System. AHS is expected to allow specially designed haul trucks to safely and efficiently operate in a mining environment without an operator on board. The evaluation, taking place in a segregated area of the North Steepbank Mine, will continue through 2017.

- Oxy-Fuel Combustion – The OTSG Oxy-Fuel Demonstration Carbon Capture Technology has the potential to result in the development of a reliable, lower cost solution to capture CO_2 from OTSGs 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 emissions of nitrogen oxide.

- Zero Liquid Discharge – Suncor uses a zero liquid discharge process at our MacKay River in situ facility and expects 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 with the goal of reducing 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 through 2018.

- N-SOLV™ – Nsolv Corporation is currently operating a pilot test of this new method of in situ bitumen recovery on Suncor's lease. The Nsolv process uses a waterless, warm vapourized solvent technology with the goal of reducing energy, GHG and water impacts. The pilot is ongoing, and Suncor is currently in the planning and optimization phase with a goal of advancing the solvent-based technology towards 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 that are expected to improve cost, SORs, and timely recovery and productivity. Monitoring and evaluation will continue throughout 2017.

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 on 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 upgrading the bitumen directly at our Oil Sands Base facilities, upgrading diluted bitumen at Suncor's Edmonton refinery, or 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 2016 decreased to 93 mbbls/d or 44% (2015 – 104 mbbls/d or 48%) of total in situ bitumen production.

	2016		2015[2]	
Sales Volumes and Operating Revenues – Principal Products	**mbbls/d**	**% operating revenues**	mbbls/d	% operating revenues
SCO and diesel (including Syncrude)	**392.0**	**88**	350.6	85
Bitumen	**117.4**	**11**	107.7	14
Byproducts and other operating revenues[1]	**n/a**	**1**	n/a	1
	509.4		458.3	

(1) Operating revenues include revenues associated with excess power from cogeneration units.

(2) Prior period figures have been restated for the re-categorization of product to better reflect the economic characteristics of the company's principal products.

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 Inc. (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. Production from Syncrude is shipped via the Pembina Syncrude Pipeline.

- 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 Edmonton and Hardisty, where Suncor has both owned storage capacity and 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.

- 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 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 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 exceeds its cumulative costs, including an annual investment allowance (the post-payout phase).

Oil Sands Base and Syncrude

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

For prior years, both Suncor and the co-owners of Syncrude reached separate agreements with the Government of Alberta for the implementation of the Royalty Framework. These agreements expired at the end of 2015.

Under Suncor's Crown Royalty Agreement, 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 2016, Suncor incurred royalties under the Royalty Framework at Oil Sands Base mining operations at a rate of 1.1% of gross revenue (2015 – 1.2% of gross revenue), a decrease from 2015 primarily due to lower oil prices. In 2016, Oil Sands Base royalties were a recovery of 1% of Oil Sands Base gross revenue (2015 – expense of 1%) due to the impact of prior year audit settlements reached in 2016.

In 2015, Syncrude continued paying a bitumen-based royalty under its Crown Agreement on the greater of 1% of gross revenue, or 25% of net revenue. In 2016, under the Royalty Framework, the royalty rate at Syncrude was 25% of net revenue (2015 – 1% of gross revenue) as the net revenue royalty was determined to be greater than the gross revenue royalty or 1% of gross revenue. In 2016, Suncor incurred royalties on Syncrude operations averaging approximately 3% of Syncrude gross revenue (2015 – 3%).

In Situ

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

In 2016, Suncor incurred royalties at an average rate of 1% of gross revenue for MacKay River (2015 – 2% of gross revenue) and royalties at an average rate of 2% of gross revenue for Firebag (2015 – 2% 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. The company plans to undertake drilling activities at Terra Nova in the second half of 2017. As at December 31, 2016, there were 30 wells: 17 oil production wells, 10 water injection wells and three gas injection wells.

In 2016, Suncor's share of Terra Nova production averaged 12 mbbls/d compared to 14 mbbls/d in 2015. Annual turnaround maintenance was completed at the Terra Nova facility in June 2016, which lasted approximately six 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, 2016, there were 70 wells: 39 oil production wells, 26 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. At the end of 2016, there were five oil production wells and eight water injection wells in the HSEU. The production wells were drilled from the GBS platform and are included in the Hibernia well count above. Of the eight water injection wells drilled in 2016, six were drilled using the mobile offshore drill rig West Aquarius at a single drill centre. Water for injection purposes is supplied from the GBS platform via a subsea flowline.

In 2016, Suncor's share of Hibernia production averaged 27 mbbls/d (2015 – 18 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, 2016, there were 37 wells: 18 oil production wells, 15 water injection wells, and four gas injection wells.

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 2017. Development of the South White Rose Extension began in 2013, with first oil being achieved in June 2015. Development drilling will continue in 2017.

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 of the project was deferred by the co-owners in response to the decline in the crude oil price environment. The co-owners are continuing to evaluate the project.

In 2016, Suncor's share of White Rose production averaged 11 mbbls/d (2015 – 12 mbbls/d). Turnaround maintenance was completed at White Rose in July 2016, which lasted approximately three weeks.

Hebron

Discovered in 1980, the Hebron oilfield is located 340 km southeast of St. John's and is operated by ExxonMobil Canada Properties (Exxon Mobil Canada). 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 2016 with integrated topside modules being successfully towed out to the deepwater construction site and mated with the GBS. Planned project activities in 2017 include sailing the GBS to its final oilfield location and the start of development drilling, with first oil expected in late 2017. Suncor's share of the post-sanction project cost estimate is approximately $2.8 billion (+/ – 10%).

Other Assets

Suncor's participation in deepwater exploration drilling in the Shelburne Basin continued in 2016. Suncor holds a 20% non-operating interest in this project, located approximately 250 km offshore Nova Scotia. Two exploration wells have been completed, with costs charged to exploration expense.

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 four to seven years. The company also holds interests in 51 significant discovery licences and nine 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, 2016, there were 48 wells: 35 oil and gas production wells and 13 water injection wells. In 2016, Suncor's share of Buzzard production averaged 46 mboe/d (2015 – 50 mboe/d). Turnaround maintenance was completed at Buzzard in October 2016, which lasted approximately five weeks.

Golden Eagle Area Development (GEAD)

GEAD, which is 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 discoveries. The development incorporates a production, utilities and accommodation platform, linked to a separate wellhead platform, with first oil achieved in October 2014. Peak production was re-rated in 2016 from 70 mboe/d (18 mboe/d net to Suncor) to 76 mboe/d (20 mboe/d net to Suncor). As at December 31, 2016, there were 19 wells: 14 oil and gas production wells and five water injection wells. In 2016, Suncor's share of GEAD production averaged 19 mboe/d (2015 – 15 mboe/d). The GEAD co-owners also hold adjacent exploration licences and continue to explore the region. Turnaround maintenance was completed at GEAD in August 2016, which lasted approximately two weeks.

Rosebank

During 2016, Suncor entered into an agreement to acquire a 30% participating interest in the Rosebank project from OMV (U.K.) Limited. This project, which was discovered in December 2004 and is operated by Chevron North Sea Limited, is located approximately 130 km northwest of the Shetland Islands, in the U.K. North Sea, in water depths of approximately 1,100 metres. The project is currently in the Front End Engineering and Design phase and has a design capacity of 100 mbbls/d (30 mbbls/d net to Suncor) of crude oil and 80 mmcf/d (24 mmcf/d net to Suncor) of natural gas. Suncor closed the purchase on October 6, 2016 for an initial payment of US$50 million. In the event the co-venturers approve the Rosebank project final investment decision and Suncor elects to participate, Suncor could pay additional consideration up to US$165 million.

Oda (Norway)

The Oda field (PL405 licence), previously known as the Butch discovery, was discovered in 2011 and is located 13 km east of the producing Ula field in the southern part of the Norwegian North Sea. Centrica plc is the operator and Suncor has a 30% working interest. The project was sanctioned in November 2016 and it is proposed that the field be developed with a subsea template that will be tied back to the Ula field. First oil is planned for 2019, with peak production expected to reach 35 mbbls/d (11 mbbls/d net to Suncor). Suncor's share of the post-sanction project cost estimate is approximately $270 million.

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. Additional wells were drilled between 2010 and 2014 confirming the size of the oil volumes in the discovery. While options to develop the discovery continue to be evaluated, uncertainty regarding the third-party processing capacity resulted in the carrying value being charged to earnings in 2016.

Suncor continues to pursue other opportunities in the North Sea and Norwegian Sea. The company holds interests in 23 exploration licences in the U.K. and Norwegian sectors of these areas.

Other International

Libya

In Libya, Suncor is a signatory to seven exploration and production sharing agreements (EPSAs) with the National Oil Company (NOC). Five of the seven EPSAs relate to fields with developed production and exploration prospects; the remaining two are exploration EPSAs related to properties 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 total oil Suncor receives for cost recovery and its share of excess petroleum is referred to as entitlement volumes. 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 the remaining value of Suncor's assets in Libya was written down in 2015. Production in Libya remained substantially shut-in through the majority of 2016 due to political unrest, with the timing of a return to normal operations remaining uncertain. 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, 2016 is US$359 million. Suncor declared force majeure for all exploration commitments in Libya effective December 14, 2014 and this declaration remains in effect.

In 2016, Suncor changed its method of recording production in Libya to reflect entitlement volumes. Suncor's share of production in Libya on this entitlement basis averaged 0.4 mbbls/d in 2016. In previous periods, Suncor reported volumes on a 50% working interest share of total production (2015 – 2.8 mbbls/d on a working-interest basis).

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 although the company believes the assets have sustained significant 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 production sharing contract (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:

Sales Volumes	2016 mboe/d	2016 % operating revenues	2015 mboe/d	2015 % operating revenues
E&P Canada				
Crude oil and NGLs	**51.6**	**46**	43.1	40
Natural gas	**2.7**	**0**	3.0	1
E&P International				
Crude oil and NGLs	**63.5**	**53**	63.0	59
Natural gas	**1.5**	**1**	1.5	0
Total Exploration and Production				
Crude oil and NGLs	**115.1**	**99**	106.1	99
Natural gas	**4.2**	**1**	4.5	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

Terra Nova has reached the net royalty stage, consisting of a two tier profit-sensitive royalty. Tier one is the greater of 10% of gross revenue or 30% of net revenue (gross revenue adjusted for eligible costs). Tier two is an additional 12.5% of net revenue. During 2016, Terra Nova royalties averaged 23% of gross revenue (2015 – 20% of gross revenue).

Hibernia production from the original oilfields and the AA Block has reached the net royalty stage, consisting of a two tier profit-sensitive royalty and an additional net profits interest (NPI) of 10% of net revenue. Tier one is the greater of 5% of gross revenue or 30% of net revenue. Tier two is an additional 12.5% of net revenue; however, this has not yet been triggered.

The HSEU royalty structure is similar to the Hibernia arrangement, but is subject to an additional tier three royalty that ranges between 2.5% and 7.5% of net revenue, depending on the price of WTI. The HSEU tier three royalty will coincide with the triggering of the tier one royalty; however, the HSEU is currently still in the basic royalty stage and subject to a royalty of 5% of gross revenue. For the portion of the HSEU that is contained within the original Hibernia licence area, the tier three royalty will range between 7.5% and 12.5% of net revenue, depending on the price of WTI.

During 2016, Hibernia (including the HSEU) royalties and NPI combined to average 19% of gross revenue (2015 – 25% of gross revenue).

The White Rose base project has reached the net royalty stage, consisting of a two tier profit-sensitive royalty. Tier one is the greater of 7.5% of gross revenue or 20% of net revenue. Tier two is an additional 10% of net revenue. The White Rose Extension tier one and two royalty structures are the same as the base project, and there is an additional tier three royalty of 6.5% of net revenue, payable if WTI is greater than US$50/bbl. The White Rose Extension is currently paying tier one and tier three royalties, but has not yet triggered tier two. During 2016, total White Rose

royalties averaged 10% of gross revenue (2015 – 11% of gross revenue).

The Hebron royalty consists of an initial sliding-scale basic royalty, followed by a three-tiered royalty which will become payable upon the achievement of specified levels of profitability. The basic royalty will start at 1% and increase to 7.5% of gross revenue depending on certain milestones. The tier one royalty is equal to 20% of net revenue. The tier two royalty is equal to an additional 10% of net revenue. The tier three royalty is equal to 6.5% of net revenue, payable if WTI is greater than US$50/bbl.

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 40% income tax rate. During 2016, 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 50% to 40%. In addition, oil and gas profits in Norway are subject to a 78% income tax rate. 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 at market prices on a spot basis or under contracts that can be terminated on short notice. Crude oil for the refinery can be supplied through several channels, including via Enbridge's Line 9, the Portland-Montreal Pipeline, by marine transportation, and by rail for inland crudes. The Montreal refinery received inland-sourced crude volumes averaging 103.3 mbbls/d in 2016.

Production 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 continues to produce feedstock sold under a long-term supply contract following the completion of the sale of Suncor's Mississauga lubricants facility in early 2017. 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 351,000 metric tonnes in 2016 (2015 – 321,000 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 operates Canada's largest ethanol facility, the St. Clair Ethanol plant in the Sarnia-Lambton region of Ontario, with a nameplate capacity of 396 million litres per year. In 2016, the plant produced 414 million litres of ethanol (2015 – 418 million litres).

Suncor closed the sale of its lubricants business to HollyFrontier on February 1, 2017 for gross proceeds of $1.125 billion, subject to customary post-closing adjustments. The lubricants plant produced specialty lubricants and waxes marketed in Canada and internationally. In 2016, the plant produced approximately 792 million litres of lubricant base stocks. Feedstock for the

lubricants facility came 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 capability to run a full slate of feedstock sourced from Suncor's oil sands operations. 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 throughput 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 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, 2016 and 2015.

Average Daily Crude Throughput	Montreal		Sarnia		Edmonton		Commerce City	
(mbbls/d, except as noted)	**2016**	2015[1]	**2016**	2015[1]	**2016**	2015[1]	**2016**	2015[1]
Sweet synthetic	**5.8**	0.3	**25.0**	30.1	**45.1**	61.0	**—**	0.6
Sour synthetic	**—**	—	**26.5**	31.2	**44.6**	33.3	**9.2**	10.0
Diluted bitumen	**25.0**	16.4	**—**	—	**40.1**	28.6	**9.1**	11.2
Sweet conventional	**89.1**	110.2	**0.3**	9.0	**0.5**	—	**64.9**	64.3
Sour conventional	**7.7**	0.4	**23.5**	10.3	**1.3**	—	**10.4**	12.0
Heavy conventional	**—**	0.1	**—**	—	**—**	—	**—**	—
Total	**127.6**	127.4	**75.3**	80.6	**131.6**	122.9	**93.6**	98.1
Utilization[2] (%)	**93**	93	**89**	95	**93**	87	**95**	100
Equity Crude Processed[3]	**10.5**	14.1	**36.4**	46.5	**108.2**	95.4	**9.16**	11.2

(1) Prior period figures have been restated for the re-categorization of crude oil throughput to better reflect the economic characteristics of the company's current crude oil mix.

(2) Refinery utilizations based on crude 2016 processing capacities (in mbbls/d): Montreal – 137; Sarnia – 85; Edmonton – 142; and Commerce City – 98.

(3) Includes Suncor's upstream operations including its working interest in Syncrude.

Refined petroleum production yield mix	Montreal		Sarnia		Edmonton		Commerce City	
(%)	**2016**	2015	**2016**	2015	**2016**	2015	**2016**	2015
Gasoline	**39**	42	**51**	48	**46**	48	**50**	48
Distillates	**34**	36	**37**	38	**50**	48	**34**	35
Other	**27**	22	**12**	14	**4**	4	**17**	17

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 ^{TM} brand. As at December 31, 2016, this network consisted of 1,493 outlets across Canada. In addition, refined products are marketed through independent dealers and joint operations. Suncor's Canadian retail network had sales of gasoline motor fuels averaging approximately 4.9 million litres per site in 2016 (2015 – 4.8 million litres) and

attracted an estimated 17.2% share (2015 – 17.8%) of the national urban retail 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. Marketing activities also generate non-petroleum revenues from convenience store sales 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:

	As at December 31	
Locations	**2016**	2015
Retail Service Stations – Canada		
Petro-Canada™-branded	**1 492**	1 484
Sunoco™-branded	**1**	1
	1 493	1 485
Retail Service Stations – Colorado		
Shell®-branded retail service stations	**35**	38
Exxon®-branded retail service stations	**7**	5
Mobil®-branded retail service stations	**2**	1
	44	44
Wholesale Cardlock Sites – Canada		
Petro-Canada™-branded cardlock sites (PETRO-PASS™)	**282**	280

	2016		2015	
Sales Volumes	**mbbls/d**	**% operating revenues**	mbbls/d	% operating revenues
Gasoline (includes motor and aviation gasoline)				
Eastern North America	**115.2**		118.9	
Western North America	**129.1**		127.3	
	244.3	**47**	246.2	47
Distillates (includes diesel and heating oils, and aviation jet fuels)				
Eastern North America	**76.3**		91.1	
Western North America	**109.8**		106.9	
	186.1	**36**	198.0	38
Other (includes heavy fuel oil, asphalts, lubricants, petrochemicals, other)				
Eastern North America	**61.8**		52.8	
Western North America	**29.2**		26.3	
	91.0	**17**	79.1	15
	521.4		523.3	

Sales volumes for specific products are moderately affected 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; asphalt sales are typically higher during the summer construction paving period. Suncor has the flexibility to modify refinery inputs and outputs to match production yields with anticipated product demands.

Sales volumes can also be impacted when refineries undergo 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 and storage and optimizes price realizations for Suncor's products. 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 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. The business provides reliable natural gas supply to Suncor's upstream and downstream operations and generates incremental revenue through trading and asset optimization.

Renewable Energy

Suncor's renewable energy investment activities include development, construction and ownership of Suncor-operated and joint venture partner-operated renewable power assets across Canada. This includes a portfolio of five operating wind power facilities located in Alberta, Saskatchewan and Ontario, as well as a portfolio of optioned lands for future wind and solar power project development. The five wind power projects in operation have a gross generating capacity of 187 MW.

The company has commenced a sale process for certain assets within the Renewable Energy business. Total gross generating capacity has decreased by 100 MW due to the sale of the Cedar Point Wind Power Project, which closed on January 24, 2017.

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

SUNCOR EMPLOYEES

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

As of December 31	2016	2015
Oil Sands[1]	**6 006**	6 008
Exploration and Production	**339**	360
Refining and Marketing	**3 401**	3 437
Corporate, Energy Trading and Renewable Energy[2]	**3 091**	3 385
Total	**12 837**	13 190

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

(2) 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 2016. The majority of the collective agreements, covering 3,717 employees represented by Unifor at various locations, were renewed in 2016. Negotiations are in progress with Unifor at the Montreal refinery and Terra Nova. Collective agreements with the Sunoco Employees' Bargaining Association, representing approximately 206 employees at the Sarnia refinery, and the Teamsters Union, representing 40 employees in B.C. terminals, will expire in 2017.

ETHICS, SOCIAL AND ENVIRONMENTAL POLICIES

Suncor has adopted several policies focused on ethics, social and environmental matters.

Suncor's standards for the ethical conduct of our business are set forth in a Standards of Business Conduct Code (the Code), which applies to Suncor's directors, officers, employees and contract workers, and requires strict compliance with legal requirements. 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 complete a Code training course, read a summary of the Code, affirm that he or she understands the requirements of the Code, and provide confirmation of compliance with the Code since his or her last affirmation 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 Governance Committee. 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 contains guiding principles such as human rights due diligence, respecting the cultures, customs and values of our employees and the communities where we operate, security policies that are consistent with international human rights standards and access to dispute resolution mechanisms. The policy makes 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 working to achieve or exceed levels of performance governed by legislation and by the evolving environmental, social and economic expectations of our 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 overseen by this committee to implement such policies and ensure compliance.

Suncor's annual President's Operational Excellence Awards support and highlight the goals of the EH&S policy by honouring 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 regularly, and are accessible to employees and contractors on the company's intranet. Additional workshops and training sessions on various matters under the policies 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 also has Cree and Dene audio translations. Training on that policy is also 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 March 1, 2017, with an effective date of December 31, 2016. 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 24, 2017.

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. and Norway (North Sea), 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 (including immaterial amounts of 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 cost 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 and the definitions and information contained in the Notes to Reserves Data Tables, Definitions for Reserves Data Tables and Notes to Future Net Revenues Tables 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, or regulatory requirements. Additional technical information regarding geology, hydro 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. 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. Political unrest, such as occurring in Syria and Libya, has resulted in unfavourable changes to reserves being reclassified to resources.

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 reserves and the future net cash flows from these reserves 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, future abandonment and reclamation 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 reserves and categorization 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 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.

Specific significant risk factors and uncertainties affecting Suncor's reserves include, amongst others:

- Volatility of Commodity Prices

  Commodity pricing affects 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 conversely 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). World oil prices have declined significantly in recent years. Low prices could have a material adverse effect on Suncor's reserves. Refer to the Risk Factors – Volatility of Commodity Prices section of this AIF.

- Carbon Risk

  Suncor operates in jurisdictions that have regulated, or have proposed to regulate industrial GHG emissions, including the laws enacted by the Government of Alberta impacting Suncor's current and future Oil Sands assets, the details of which are set forth in the Industry Conditions – Environmental Regulation – Climate Change section of this AIF. Such laws could impose significant compliance costs on Suncor, which could potentially impact the economic viability of certain projects recorded as reserves, or could necessitate the development of new technologies in order to comply, the absence of which could impact future development. Refer to the Risk Factors – Carbon Risk section of this AIF.

- Political Instability

  As a result of political instability in Syria, Suncor reclassified all Syria reserves to contingent resources effective December 31, 2012. All Syria volumes remain classified as contingent resources as at December 31, 2016. Suncor has also reclassified all Libya reserves to contingent resources effective December 31, 2016 due to the ongoing political instability and uncertainty in Libya. The criteria for the reclassification of the aforementioned volumes back to reserves include sustained periods of political stability, operational and production stability, and normalization of business relations including financial transactions. Refer to the Risk Factors – Foreign Operations section of this AIF.

- Abandonment and Reclamation costs

  Refer to the Additional Information Relating to Reserves Data – Abandonment and Reclamation Costs section below.

Refer to the Risk Factors section of this AIF for additional information on significant risk factors and uncertainties affecting Suncor's reserves.

Oil and Gas Reserves Tables and Notes

Summary of Oil and Gas Reserves [1]
as at December 31, 2016
(forecast prices and costs)[2]

	SCO[3] (mmbbls)		Bitumen (mmbbls)		Light Crude & Medium Crude Oil[4] (mmbbls)		Conventional Natural Gas[5] (bcfe)		Total (mmboe)	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Proved Developed Producing										
Mining	2 317	2 073	—	—	—	—	—	—	2 317	2 073
In Situ	153	147	117	107	—	—	—	—	270	254
E&P Canada	—	—	—	—	57	44	26	23	61	47
Total Canada	2 470	2 220	117	107	57	44	26	23	2 648	2 375
North Sea	—	—	—	—	69	69	4	4	69	69
Total Proved Developed Producing	**2 470**	**2 220**	**117**	**107**	**125**	**112**	**29**	**26**	**2 717**	**2 444**
Proved Developed Non-Producing										
Mining	—	—	—	—	—	—	—	—	—	—
In Situ	17	14	14	14	—	—	—	—	32	28
E&P Canada	—	—	—	—	—	—	2	1	—	—
Total Canada	17	14	14	14	—	—	2	1	32	28
North Sea	—	—	—	—	—	—	—	—	—	—
Total Proved Developed Non-Producing	**17**	**14**	**14**	**14**	**—**	**—**	**2**	**1**	**32**	**28**
Proved Undeveloped										
Mining	—	—	879	812	—	—	—	—	879	812
In Situ	576	493	694	589	—	—	—	—	1 269	1 081
E&P Canada	—	—	—	—	47	44	—	—	47	44
Total Canada	576	493	1 573	1 401	47	44	—	—	2 195	1 938
North Sea	—	—	—	—	—	—	—	—	—	—
Total Proved Undeveloped	**576**	**493**	**1 573**	**1 401**	**47**	**44**	**—**	**—**	**2 195**	**1 938**
Proved										
Mining	2 317	2 073	879	812	—	—	—	—	3 196	2 886
In Situ	746	653	825	710	—	—	—	—	1 571	1 363
E&P Canada	—	—	—	—	104	88	27	24	108	92
Total Canada	3 063	2 727	1 704	1 522	104	88	27	24	4 875	4 341
North Sea	—	—	—	—	69	69	4	4	69	69
Total Proved	**3 063**	**2 727**	**1 704**	**1 522**	**172**	**156**	**31**	**28**	**4 944**	**4 410**
Probable										
Mining	617	542	577	491	—	—	—	—	1 194	1 034
In Situ	1 169	945	410	311	—	—	—	—	1 579	1 256
E&P Canada	—	—	—	—	206	169	8	7	208	170
Total Canada	1 786	1 487	987	803	206	169	8	7	2 981	2 460
North Sea	—	—	—	—	32	32	4	4	33	33
Total Probable	**1 786**	**1 487**	**987**	**803**	**238**	**201**	**12**	**11**	**3 014**	**2 493**
Proved Plus Probable										
Mining	2 934	2 615	1 455	1 304	—	—	—	—	4 389	3 919
In Situ	1 915	1 598	1 235	1 021	—	—	—	—	3 150	2 620
E&P Canada	—	—	—	—	310	257	35	31	316	262
Total Canada	4 849	4 214	2 691	2 325	310	257	35	31	7 855	6 801
North Sea	—	—	—	—	101	101	8	8	102	102

Total Proved Plus Probable	**4 849**	**4 214**	**2 691**	**2 325**	**411**	**358**	**43**	**39**	**7 957**	**6 903**

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

Reconciliation of Gross Reserves[1]
as at December 31, 2016
(forecast prices and costs)[2]

	SCO[3]			Bitumen			Light Crude & Medium Crude Oil[4][6]			Conventional Natural Gas[5]			Total		
	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, 2015	1 673	494	2 167	1 052	542	1 593	—	—	—	—	—	—	2 725	1 035	3 760
Extensions & Improved Recovery[7]	5	66	70	—	—	—	—	—	—	—	—	—	5	66	70
Technical Revisions[8]	24	(268)	(244)	(173)	35	(138)	—	—	—	—	—	—	(149)	(233)	(382)
Discoveries[9]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Acquisitions[10]	731	326	1 057	—	—	—	—	—	—	—	—	—	731	326	1 057
Dispositions[11]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors[12]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Production[13]	(116)	—	(116)	—	—	—	—	—	—	—	—	—	(116)	—	(116)
December 31, 2016	**2 317**	**617**	**2 934**	**879**	**577**	**1 455**	**—**	**—**	**—**	**—**	**—**	**—**	**3 196**	**1 194**	**4 389**
In Situ															
December 31, 2015	769	1 257	2 025	866	305	1 170	—	—	—	—	—	—	1 634	1 561	3 196
Extensions & Improved Recovery[7]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Technical Revisions[8]	4	(88)	(84)	2	106	107	—	—	—	—	—	—	5	18	23
Discoveries[9]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Acquisitions[10]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions[11]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors[12]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Production[13]	(26)	—	(26)	(42)	—	(42)	—	—	—	—	—	—	(69)	—	(69)
December 31, 2016	**746**	**1 169**	**1 915**	**825**	**410**	**1 235**	**—**	**—**	**—**	**—**	**—**	**—**	**1 571**	**1 579**	**3 150**
E&P Canada															
December 31, 2015	—	—	—	—	—	—	107	211	318	34	13	47	113	213	326
Extensions & Improved Recovery[7]	—	—	—	—	—	—	1	7	8	—	—	—	1	7	8

Technical Revisions[8]	—	—	—	—	—	—	15	(13)	2	—	(4)	(3)	15	(14)	1
Discoveries[9]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Acquisitions[10]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions[11]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors[12]	—	—	—	—	—	—	(1)	1	—	(1)	(1)	(3)	(1)	1	—
Production[13]	—	—	—	—	—	—	(18)	—	(18)	(6)	—	(6)	(19)	—	(19)
December 31, 2016	**—**	**—**	**—**	**—**	**—**	**—**	**104**	**206**	**310**	**27**	**8**	**35**	**108**	**208**	**316**
Total Canada															
December 31, 2015	2 442	1 750	4 192	1 917	846	2 764	107	211	318	34	13	47	4 473	2 810	7 282
Extensions & Improved Recovery[7]	5	66	70	—	—	—	1	7	8	—	—	—	6	73	78
Technical Revisions[8]	28	(356)	(328)	(171)	141	(31)	15	(13)	2	—	(4)	(3)	(129)	(229)	(357)
Discoveries[9]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Acquisitions[10]	731	326	1 057	—	—	—	—	—	—	—	—	—	731	326	1 057
Dispositions[11]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors[12]	—	—	—	—	—	—	(1)	1	—	(1)	(1)	(3)	(1)	1	—
Production[13]	(143)	—	(143)	(42)	—	(42)	(18)	—	(18)	(6)	—	(6)	(204)	—	(204)
December 31, 2016	**3 063**	**1 786**	**4 849**	**1 704**	**987**	**2 691**	**104**	**206**	**310**	**27**	**8**	**35**	**4 875**	**2 981**	**7 855**

Please see Notes (1) through (13) at the end of the reserves data section for important information about volumes in this table.

Reconciliation of Gross Reserves[1] *(continued)*
as at December 31, 2016
(forecast prices and costs)[2]

	SCO[3]			Bitumen			Light Crude & Medium Crude Oil[4][6]			Conventional Natural Gas[5]			Total		
	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, 2015	—	—	—	—	—	—	67	26	94	4	2	6	68	26	94
Extensions & Improved Recovery[7]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Technical Revisions[8]	—	—	—	—	—	—	24	(4)	19	4	(1)	3	24	(4)	20
Discoveries[9]	—	—	—	—	—	—	—	10	10	—	3	3	—	11	11
Acquisitions[10]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions[11]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors[12]	—	—	—	—	—	—	—	—	1	—	—	—	—	—	1
Production[13]	—	—	—	—	—	—	(23)	—	(23)	(4)	—	(4)	(24)	—	(24)
December 31, 2016	**—**	**—**	**—**	**—**	**—**	**—**	**69**	**32**	**101**	**4**	**4**	**8**	**69**	**33**	**102**
Other International [14]															
December 31, 2015	—	—	—	—	—	—	138	95	233	—	—	—	138	95	233
Extensions & Improved Recovery[7]	—	—	—	—	—	—	—	—	—	—	—	—			
Technical Revisions[8]	—	—	—	—	—	—	(137)	(95)	(232)	—	—	—	(137)	(95)	(232)
Discoveries[9]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Acquisitions[10]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions[11]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors[12]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Production[13]	—	—	—	—	—	—	(1)	—	(1)	—	—	—	(1)	—	(1)
December 31, 2016	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Total															
December 31, 2015	2 442	1 750	4 192	1 917	846	2 764	313	332	645	38	15	53	4 679	2 931	7 610
Extensions & Improved Recovery[7]	5	66	70	—	—	—	1	7	8	—	—	—	6	73	78
Technical Revisions[8]	28	(356)	(328)	(171)	141	(31)	(99)	(112)	(211)	4	(5)	—	(241)	(328)	(569)
Discoveries[9]	—	—	—	—	—	—	—	10	10	—	3	3	—	11	11

Acquisitions[10]	731	326	1 057	—	—	—	—	—	—	—	—	—	731	326	1 057
Dispositions[11]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors[12]	—	—	—	—	—	—	(1)	1	1	(1)	(1)	(3)	(1)	1	—
Production[13]	(143)	—	(143)	(42)	—	(42)	(43)	—	(43)	(10)	—	(10)	(229)	—	(229)
December 31, 2016	**3 063**	**1 786**	**4 849**	**1 704**	**987**	**2 691**	**172**	**238**	**411**	**31**	**12**	**43**	**4 944**	**3 014**	**7 957**

Please see Notes (1) through (14) 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, 2016

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

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

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

(4) Gross volumes of Light Crude and Medium Crude oil for E&P Canada includes quantities of Heavy Crude oil as follows: Proved Undeveloped of 27 mmbbls, Proved of 27 mmbbls, Probable of 84 mmbbls and Proved Plus Probable of 111 mmbbls. Net volumes for E&P Canada include quantities of Heavy Crude oil as follows: Proved Undeveloped of 27 mmbbls, Proved of 27 mmbbls, Probable of 75 mmbbls and Proved Plus Probable of 102 mmbbls.

(5) Conventional Natural Gas includes immaterial amounts of NGLs (0.3 mmbbls of total proved and 0.4 mmbbls of total proved plus probable NGLs).

(6) Light Crude and Medium Crude oil Technical Revisions for E&P Canada includes quantities of Heavy Crude oil as follows: Proved of (2) mmbbls and Probable of 2 mmbbls.

(7) 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. Changes in 2016 are primarily a result of mine development plan changes at Syncrude and infill drilling in East Coast Canada properties.

(8) Technical Revisions include changes in previous estimates resulting from new technical data or revised interpretations. Changes in 2016 are primarily a result of mine development plan changes at Syncrude and Fort Hills and the reclassification of Libya reserves to contingent resources due to ongoing political instability.

(9) Discoveries are additions to reserves in reservoirs where no reserves were previously booked. Changes in 2016 primarily relate to reserves associated with the Oda property in Norway.

(10) Acquisitions are additions to reserves estimates as a result of purchasing interests in oil and gas properties. Additions in 2016 relate to Suncor's acquisition of additional interests in Syncrude.

(11) Dispositions are reductions in reserves estimates as a result of selling all or a portion of an interest in oil and gas properties.

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

(13) Production quantities may include estimated production for periods near the end of the year when actual sales quantities were not available at the time the reserves evaluation was conducted.

(14) Other International, reported as at December 31, 2015, was comprised of quantities of crude oil in Libya which were expected to be produced under EPSAs. Under these EPSAs, net proved and probable reserves were determined using the economic interest method. See the Reserves Categories section for a description of the economic interest method. Due to ongoing political unrest in Libya and the resulting high level of uncertainty regarding resumption or continuation of production, these reserves have been reclassified to contingent resources.

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, 2016
(forecast prices and costs)

	(in $ millions, discounted at % per year)					Unit Value[2]
	0%	5%	10%	15%	20%	($/boe)
Proved Developed Producing						
Mining	34 194	29 557	21 852	16 646	13 239	10.54
In Situ	6 415	5 946	5 478	5 052	4 676	21.57
E&P Canada	937	1 042	1 059	1 039	1 006	22.32
Total Canada	41 546	36 545	28 389	22 738	18 921	11.95
North Sea	3 131	2 933	2 729	2 539	2 367	39.49
Total Proved Developed Producing	44 677	39 478	31 118	25 277	21 288	12.73
Proved Developed Non-Producing						
Mining	—	—	—	—	—	—
In Situ	941	786	666	573	498	23.79
E&P Canada	1	1	1	1	1	3.61
Total Canada	942	787	667	574	499	23.61
North Sea	—	—	—	—	—	—
Total Proved Developed Non-Producing	942	787	667	574	499	23.61
Proved Undeveloped						
Mining	11 596	4 363	1 481	203	(419)	1.82
In Situ	30 035	15 854	8 960	5 346	3 316	8.29
E&P Canada	1 082	784	553	377	244	12.51
Total Canada	42 712	21 001	10 993	5 926	3 141	5.67
North Sea	—	—	—	—	—	—
Total Proved Undeveloped	42 712	21 001	10 993	5 926	3 141	5.67
Proved						
Mining	45 790	33 920	23 332	16 850	12 820	8.09
In Situ	37 391	22 586	15 105	10 971	8 491	11.08
E&P Canada	2 020	1 828	1 613	1 417	1 250	17.55
Total Canada	85 201	58 333	40 049	29 238	22 560	9.23
North Sea	3 131	2 933	2 729	2 539	2 367	39.49
Total Proved	88 332	61 266	42 779	31 777	24 928	9.70
Probable						
Mining	33 060	13 549	7 163	4 451	3 080	6.93
In Situ	67 857	19 976	8 166	4 445	2 957	6.50
E&P Canada	10 365	6 593	4 452	3 182	2 377	26.17
Total Canada	111 282	40 119	19 780	12 078	8 414	8.04
North Sea	1 645	1 320	1 060	859	706	32.23
Total Probable	112 927	41 439	20 840	12 937	9 121	8.36
Proved Plus Probable						
Mining	78 850	47 469	30 495	21 301	15 899	7.78
In Situ	105 248	42 562	23 270	15 416	11 448	8.88
E&P Canada	12 385	8 421	6 065	4 599	3 628	23.14

Total Canada	196 483	98 452	59 830	41 316	30 975	8.80
North Sea	4 776	4 253	3 789	3 398	3 074	37.15
Total Proved Plus Probable	201 259	102 705	63 618	44 714	34 049	9.22

Please see the Notes at the end of the Future Net Revenues Tables.

Net Present Value of Future Net Revenues After Income Taxes [1]
as at December 31, 2016
(forecast prices and costs)

	(in $ millions, discounted at % per year)				
	0%	5%	10%	15%	20%
Proved Developed Producing					
Mining	23 852	22 946	17 348	13 408	10 802
In Situ	4 925	4 605	4 261	3 937	3 647
E&P Canada	937	1 042	1 059	1 039	1 006
Total Canada	29 715	28 593	22 668	18 385	15 455
North Sea	1 810	1 705	1 594	1 489	1 394
Total Proved Developed Producing	31 524	30 298	24 262	19 874	16 850
Proved Developed Non-Producing					
Mining	—	—	—	—	—
In Situ	691	574	485	415	360
E&P Canada	1	1	1	1	1
Total Canada	692	575	485	416	361
North Sea	—	—	—	—	—
Total Proved Developed Non-Producing	692	575	485	416	361
Proved Undeveloped					
Mining	9 054	3 235	946	(51)	(529)
In Situ	21 513	11 142	6 143	3 550	2 110
E&P Canada	994	725	512	347	222
Total Canada	31 561	15 102	7 601	3 846	1 803
North Sea	—	—	—	—	—
Total Proved Undeveloped	31 561	15 102	7 601	3 846	1 803
Proved					
Mining	32 906	26 180	18 294	13 357	10 273
In Situ	27 129	16 321	10 888	7 902	6 118
E&P Canada	1 932	1 769	1 572	1 387	1 228
Total Canada	61 968	44 271	30 754	22 647	17 619
North Sea	1 810	1 705	1 594	1 489	1 394
Total Proved	63 778	45 975	32 348	24 136	19 014
Probable					
Mining	24 639	9 844	5 081	3 106	2 125
In Situ	49 267	14 411	5 915	3 250	2 179
E&P Canada	7 589	4 885	3 286	2 334	1 733
Total Canada	81 495	29 140	14 283	8 690	6 037
North Sea	900	721	576	464	379
Total Probable	82 395	29 860	14 858	9 154	6 417
Proved Plus Probable					
Mining	57 545	36 025	23 376	16 463	12 398
In Situ	76 396	30 732	16 803	11 152	8 297
E&P Canada	9 521	6 654	4 858	3 721	2 961
Total Canada	143 462	73 410	45 037	31 337	23 656

North Sea	2 710	2 425	2 170	1 954	1 774
Total Proved Plus Probable	146 172	75 836	47 207	33 290	25 430

See the Notes at the end of the Future Net Revenues Tables.

Total Future Net Revenues[1]
as at December 31, 2016
(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	216 733	23 469	110 077	29 306	19 687	34 194	10 341	23 852
In Situ	17 633	926	7 696	2 089	507	6 415	1 490	4 925
E&P Canada	4 669	1 044	1 496	110	1 083	937	—	937
Total Canada	239 036	25 440	119 269	31 504	21 277	41 546	11 831	29 715
North Sea	5 469	—	1 663	123	551	3 131	1 322	1 810
Total Proved Developed Producing	244 505	25 440	120 932	31 627	21 828	44 677	13 153	31 524
Proved Developed Non-Producing								
Mining	—	—	—	—	—	—	—	—
In Situ[3]	2 184	291	743	195	14	941	250	691
E&P Canada	6	—	4	1	1	1	—	1
Total Canada	2 190	291	746	196	14	942	250	692
North Sea	—	—	—	—	—	—	—	—
Total Proved Developed Non-Producing	2 190	291	746	196	14	942	250	692
Proved Undeveloped								
Mining	59 298	4 736	34 089	7 711	1 166	11 596	2 542	9 054
In Situ	106 443	15 472	36 286	23 423	1 228	30 035	8 522	21 513
E&P Canada	3 967	223	1 246	1 000	417	1 082	87	994
Total Canada	169 708	20 430	71 621	32 134	2 811	42 712	11 151	31 561
North Sea	—	—	—	—	—	—	—	—
Total Proved Undeveloped	169 708	20 430	71 621	32 134	2 811	42 712	11 151	31 561
Proved								
Mining	276 031	28 205	144 166	37 017	20 853	45 790	12 883	32 906
In Situ	126 260	16 690	44 724	25 707	1 749	37 391	10 262	27 129
E&P Canada	8 643	1 267	2 746	1 110	1 500	2 020	87	1 932
Total Canada	410 934	46 161	191 636	63 834	24 102	85 201	23 233	61 968
North Sea	5 469	—	1 663	123	551	3 131	1 322	1 810
Total Proved	416 402	46 161	193 299	63 957	24 653	88 332	24 555	63 778
Probable								
Mining	127 083	17 206	61 231	13 160	2 427	33 060	8 421	24 639
In Situ	204 093	38 605	59 170	36 902	1 559	67 857	18 590	49 267
E&P Canada	20 729	3 731	4 686	1 363	583	10 365	2 776	7 589
Total Canada	351 905	59 543	125 087	51 425	4 568	111 282	29 787	81 495
North Sea	2 935	—	934	275	81	1 645	745	900
Total Probable	354 839	59 543	126 021	51 700	4 649	112 927	30 532	82 395
Proved Plus Probable								
Mining	403 114	45 411	205 397	50 177	23 279	78 850	21 304	57 545
In Situ	330 353	55 295	103 894	62 609	3 307	105 248	28 852	76 396

E&P Canada	29 371	4 998	7 432	2 473	2 083	12 385	2 864	9 521
Total Canada	762 838	105 704	316 723	115 259	28 670	196 483	53 020	143 462
North Sea	8 404	—	2 598	398	632	4 776	2 067	2 710
Total Proved Plus Probable	771 242	105 704	319 320	115 657	29 302	201 259	55 087	146 172

See the Notes at the end of the Future Net Revenues Tables.

Future Net Revenues by Product Type[1]
as at December 31, 2016
(forecast prices and costs)

(before income taxes, discounted at 10% per year)	$ millions	Unit Value $/boe[2]
Proved Developed Producing		
SCO	25 919	11.68
Bitumen	1 410	13.13
Light Crude & Medium Crude Oil[3]	3 755	33.47
Heavy Crude Oil	—	—
Conventional Natural Gas[4]	33	7.61
Total Proved Developed Producing	31 118	12.73
Proved		
SCO	31 269	11.47
Bitumen	7 167	4.71
Light Crude & Medium Crude Oil[3]	3 994	30.88
Heavy Crude Oil	314	11.59
Conventional Natural Gas[4]	34	7.39
Total Proved	42 779	9.70
Proved Plus Probable		
SCO	44 905	10.66
Bitumen	8 860	3.81
Light Crude & Medium Crude Oil[3]	7 507	29.30
Heavy Crude Oil	2 301	22.71
Conventional Natural Gas[4]	46	7.08
Total Proved Plus Probable	63 618	9.22

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

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

Notes to Future Net Revenues Tables

In Situ Future Net Revenues

Future net revenues for In Situ properties 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 49-55% of Firebag bitumen production is upgraded to SCO from 2017 to 2034 and 100% thereafter (for total proved plus probable reserves). These assumptions have resulted in a $3.0 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, 2017. Resultant forecasts are set out below. To the extent 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 2017 and 2.0% 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[9]	43.75	43.45	29.55	51.90	47.45	2.15	1.76	4.70
2017	56.00	55.00	53.38	68.24	70.95	3.43	3.00	7.78
2018	61.90	60.90	58.95	73.16	75.40	3.17	2.78	7.80
2019	66.47	65.47	62.70	76.25	78.72	3.26	2.94	7.71
2020	70.50	69.13	65.48	79.37	81.52	3.67	3.35	8.11
2021	74.58	73.21	68.39	82.56	84.77	3.86	3.54	8.18
2022	76.56	75.19	70.49	84.85	87.17	3.97	3.65	8.35
2023	78.56	77.19	72.58	87.15	89.44	4.11	3.76	8.51
2024	80.60	79.23	74.73	89.50	91.86	4.23	3.88	8.69
2025	82.68	81.28	76.88	91.89	94.67	4.31	3.96	8.86
2026	84.98	83.39	79.08	94.01	96.73	4.41	4.06	9.04
2027	86.65	85.03	80.64	95.85	98.66	4.51	4.16	9.22
2028	88.37	86.73	82.25	97.78	100.62	4.60	4.24	9.40
2029	90.19	88.48	83.89	99.74	102.65	4.68	4.32	9.59
2030	91.99	90.26	85.61	101.76	104.73	4.77	4.41	9.78
2031	93.82	92.06	87.29	103.78	106.81	4.87	4.51	9.97
2032+	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/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 and North Sea 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.

(9) Prices for 2016 reflect the company's historical weighted average prices.

Foreign Exchange Rates Impacting Forecast Prices

Forecast	US$/Cdn$ Exchange Rate	Cdn$/€ Exchange Rate	Cdn$/£ Exchange Rate
Year			
2017	0.760	1.382	1.711
2018	0.790	1.329	1.677
2019	0.817	1.286	1.622
2020	0.833	1.260	1.590
2021	0.850	1.235	1.559
2022+	0.850	1.235	1.559

Disclosure of After-Tax Net Present Value 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. 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 2016 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, 2016
(forecast prices and costs)

($ millions)	2017	2018	2019	2020	2021	Remainder	Total	Discounted At 10%
Proved								
Mining	2 632	2 053	1 648	1 700	1 696	27 288	37 017	17 037
In Situ	603	819	946	983	1 097	21 259	25 707	9 489
E&P Canada	446	94	42	107	69	352	1 110	825
Total Canada	3 681	2 967	2 637	2 790	2 861	48 898	63 834	27 352
North Sea	24	10	8	11	11	59	123	87
Total Proved	3 705	2 976	2 645	2 801	2 873	48 958	63 957	27 439
Proved Plus Probable								
Mining	2 704	2 179	1 855	1 882	1 890	39 668	50 177	19 810
In Situ	393	977	904	947	934	58 454	62 609	10 901
E&P Canada	604	289	237	246	122	975	2 473	1 673
Total Canada	3 701	3 445	2 996	3 075	2 945	99 097	115 259	32 383
North Sea	74	114	70	12	13	115	398	313
Total Proved Plus Probable	3 776	3 559	3 066	3 087	2 958	99 211	115 657	32 696

(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 2017 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 expected to 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, continuation and completion of construction activities and the start of platform drilling at Hebron, as well as development drilling at Hibernia, White Rose and Terra Nova.
- For E&P International, activities focus on development of the Norwegian Oda project.

Management currently believes that internally generated cash flows, existing and future credit facilities and, if needed, the divestiture of non-core assets and accessing capital markets will be 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 provided by 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, 2016, Suncor estimated its undiscounted, uninflated abandonment and reclamation costs for its upstream assets to be approximately $11.5 billion (discounted at 10%, approximately $2.9 billion) excluding Refining and Marketing liabilities ($0.2 billion, undiscounted and uninflated). Abandonment and reclamation costs are limited to current disturbances at December 31, 2016 for Suncor's assets, except for Syncrude which is estimated on a life of mine basis, where it is assumed that material from future disturbances will be required to settle the existing obligation at December 31, 2016. Suncor estimates that it will incur $1.3 billion of its identified abandonment and reclamation costs during the next three years (undiscounted: 2017 – $0.4 billion, 2018 – $0.4 billion, 2019 – $0.5 billion), more than 78% of which is associated with Oil Sands mining operations.

The abandonment and reclamation cost estimates included in the net present values of the company's proved and probable reserves 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 reserve wells and associated service wells, disturbed lease sites, and future lease site disturbances. Approximately $29.3 billion (inflated and undiscounted) has been deducted as abandonment and reclamation costs in estimating the future net revenues from proved plus probable reserves, including $26.6 billion related to the company's oil sands upgraders, extraction facilities, tailings ponds, subsurface wells and central processing facilities, which includes amounts related to current disturbances.

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)

	2014		2015		**2016**	
	First Attributed	Total at December 31 2014	First Attributed	Total at December 31 2015	**First Attributed**	**Total at December 31 2016**
SCO (mmbbls)						
Mining	—	—	—	—	—	—
In Situ	—	532	—	584	—	**576**
Total SCO	—	532	—	584	—	**576**
Bitumen (mmbbls)						
Mining	—	845	207	1 052	—	**879**
In Situ	—	830	—	741	—	**694**
Total Bitumen	—	1 674	207	1 792	—	**1 573**
Light Crude & Medium Crude Oil (mmbbls)						
E&P Canada	38	52	—	22	**1**	**19**
North Sea	—	16	—	10	—	—
Other International[2]	—	2	—	51	—	—
Total Light Crude & Medium Crude Oil	38	70	—	83	**1**	**19**
Heavy Crude Oil (mmbbls)						
E&P Canada	—	—	—	30	—	**27**
North Sea	—	—	—	—	—	—
Other International[2]	—	—	—	—	—	—
Total Heavy Crude Oil	—	—	—	30	—	**27**
Conventional Natural Gas (bcfe)[3]						
E&P Canada	—	—	—	—	—	—
North Sea	—	1	—	1	—	—
Other International[2]	—	—	—	—	—	—
Total Conventional Natural Gas	—	1	—	1	—	—
Total (mmboe)	38	2 277	207	2 488	**1**	**2 195**

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

	2014		2015		2016	
	First Attributed	Total at December 31 2014	First Attributed	Total at December 31 2015	**First Attributed**	**Total at December 31 2016**
SCO (mmbbls)						
Mining	—	265	—	265	**285**	**285**
In Situ	—	1 112	—	1 207	**—**	**1 118**
Total SCO	—	1 378	—	1 473	**285**	**1 403**
Bitumen (mmbbls)						
Mining	—	408	107	542	**—**	**577**
In Situ	—	268	—	250	**—**	**347**
Total Bitumen	—	677	107	791	**—**	**924**
Light Crude & Medium Crude Oil (mmbbls)						
E&P Canada	10	189	5	88	**7**	**79**
North Sea	—	13	—	4	**10**	**10**
Other International[2]	1	3	—	42	**—**	**—**
Total Light Crude & Medium Crude Oil	11	205	5	133	**17**	**89**
Heavy Crude Oil (mmbbls)						
E&P Canada	—	—	—	82	**—**	**84**
North Sea	—	—	—	—	**—**	**—**
Other International[2]	—	—	—	—	**—**	**—**
Total Heavy Crude Oil	—	—	—	82	**—**	**84**
Conventional Natural Gas (bcfe)[3]						
E&P Canada	—	3	—	2	**—**	**—**
North Sea	—	1	—	1	**3**	**3**
Other International[2]	—	—	—	—	**—**	**—**
Total Conventional Natural Gas	—	4	—	3	**3**	**3**
Total (mmboe)	11	2 260	112	2 479	**303**	**2 500**

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

(2) Other International includes certain volumes for Libya that have been reclassified to contingent resources due to political uncertainty and facility damage.

(3) Includes immaterial amounts of NGLs (less than 0.4 mmbbls).

Undeveloped In Situ reserves, which constitute approximately 58% 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 proved and probable undeveloped reserves development activity. Further delineation is pursued through annual core hole drilling programs. 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 10 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 40% of Suncor's gross proved undeveloped reserves and 34% of Suncor's gross probable undeveloped reserves, and relate to the Fort Hills mining project and the Syncrude Mildred Lake Extension-West mining areas, which are well-delineated by core hole drilling. Regulatory approvals are in place for the Fort Hills mining project and application for approval has been submitted for the Syncrude Mildred Lake Extension-West mining area. Suncor is currently completing construction of the Fort Hills mining area, and first oil remains on track for late 2017.

Undeveloped conventional reserves (light crude oil and medium crude oil, heavy crude oil and natural gas) constitute approximately 2% of Suncor's gross proved undeveloped reserves and approximately 7% 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 late 2017), and under-drilled or undrilled fault blocks related to areas in Hibernia, White Rose and Terra Nova. Due to ongoing political unrest in Libya and the resulting high level of uncertainty regarding resumption or continuation of production, the reserves associated with Libya have been reclassified to contingent resources. 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, 2016. 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	6 570 563	3 695 452
Libya[(1)]	3 117 800	1 422 900
U.S. – Alaska	481 740	160 564
Syria	345 194	345 194
Norway	305 429	96 562
U.K.	110 530	33 194
Australia (overriding royalty interest only)	113 027	—
Total	11 044 283	5 753 866

(1) Includes lands associated with the reclassification of reserves to contingent resources in 2016 due to the high level of uncertainty regarding resumption or continuation of production as a result of the ongoing political unrest.

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 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. Refer to the Risk Factors section of this AIF for additional information on risks and uncertainties.

In 2017, Suncor's rights to 29,966 net hectares in Canada, 64,705 net hectares in Norway and 14,689 net hectares in the U.K. are scheduled to expire. The expiries include approximately 1,237 net hectares in In Situ and 2,310 net hectares in Mining. Substantial portions of expiring lands may have their tenure continued beyond 2017 through the conduct of work programs and/or the payment of prescribed fees to the rights owner.

Oil and Gas Properties and Wells

For descriptions of Suncor's important properties, plants, facilities and installations, refer to the Narrative Description of Suncor's Businesses section within this AIF.

The following table is a summary of oil and gas wells as at December 31, 2016.

	Oil Wells[1]				Natural Gas Wells[1]			
	Producing		Non-Producing[2][3]		Producing		Non-Producing[2][3]	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta – In Situ[4]	300.0	300.0	96.0	96.0	—	—	—	—
British Columbia	—	—	—	—	28.0	26.5	21.0	16.9
Newfoundland and Labrador	72.0	18.5	3.0	0.8	—	—	—	—
North Sea	44.0	12.7	5.0	1.5	—	—	—	—
Other International[5]	—	—	419.0	211.1	—	—	6.0	6.0
Total	416.0	331.2	523.0	309.4	28.0	26.5	27.0	22.9

(1) All oil and gas wells are onshore, other than Newfoundland and Labrador 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 reserves associated with wells in Syria or 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.

Costs Incurred

The table below summarizes the company's costs incurred related to its oil and gas activities for the year ended December 31, 2016.

($ millions)	Exploration Costs	Proved Property Acquisition Costs	Unproved Property Acquisition Costs	Development Costs	Total
Canada – Mining and In Situ	45	10 806	684	4 272	15 807
Canada – E&P Canada	150	—	—	743	893
Total Canada	195	10 806	684	5 015	16 700
North Sea	49	—	68	88	205
Other International	13	—	—	—	13
Total	257	10 806	752	5 103	16 918

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, 2016.

	Exploratory Wells[1]		Development Wells	
Total number of wells completed	Gross	Net	Gross	Net
Canada – Oil Sands				
Oil	2.0	2.0	—	—
Service[2]	2.0	2.0	—	—
Stratigraphic Test[3]	105.0	92.4	—	—
Total	109.0	96.4	—	—
Canada – E&P Canada				
Oil	—	—	3	0.7
Dry Hole	1	0.2	—	—
Natural Gas	—	—	—	—
Service[2]	—	—	4	0.8
Stratigraphic Test	—	—	—	—
Total	1	0.2	7	1.5
North Sea				
Oil	1	0.6	5	1.3
Service[2]	—	—	1	0.3
Dry Hole			1	0.3
Stratigraphic Test	—	—	—	—
Total	1	0.6	7	1.9

(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 2016 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 the HSEU, White Rose and the South White Rose Extension, and exploration drilling in the Shelburne Basin.
- In the U.K. North Sea, development drilling of Golden Eagle continued.

For significant exploration and development activities expected to occur in 2017 and beyond, see Narrative Description of Suncor's Businesses and Future Development Costs herein.

Production History[1]

2016	Q1	Q2	Q3	Q4	Year Ended
Canada – Oil Sands					
Total production (mbbls/d)	**565.8**	**213.1**	**617.5**	**620.4**	**504.9**
Bitumen Production (mbbls/d)	**130.7**	**91.1**	**132.6**	**108.9**	**115.9**
($/bbl)					
Average price realized[2]	12.0	23.90	26.67	31.68	23.50
Royalties	—	(0.24)	(0.39)	(0.33)	(0.23)
Production costs	(15.38)	(20.34)	(15.53)	(15.51)	(16.63)
Netback[5]	(3.38)	3.32	10.75	15.84	6.64
SCO and diesel (mbbls/d)	**322.3**	**86.4**	**301.1**	**324.5**	**258.9**
($/bbl)					
Average price realized[2]	43.27	52.58	56.69	62.28	53.53
Royalties	(0.57)	(0.33)	(0.42)	2.74	0.50
Production costs	(31.32)	(67.99)	(27.99)	(30.85)	(34.01)
Netback[5]	11.38	(15.74)	28.28	34.17	20.02
Syncrude (mbbls/d)	**112.8**	**35.6**	**183.8**	**187.0**	**130.1**
($/bbl)					
Average price realized[2]	44.93	59.34	58.62	64.28	56.91
Royalties	(0.18)	(0.98)	(0.26)	(4.70)	(1.90)
Production costs	(28.61)	(104.05)	(25.34)	(29.53)	(32.58)
Netback[5]	16.14	(45.69)	33.02	30.05	22.43
Canada – Light Crude & Medium Crude Oil [3]					
Total production (mbbls/d)	**50.6**	**41.7**	**50.4**	**57.7**	**50.1**
($/bbl)					
Average price realized[2]	46.17	62.39	61.63	68.06	59.31
Royalties	(5.51)	(11.06)	(10.93)	(15.07)	(10.64)
Production costs	(15.40)	(16.81)	(15.90)	(11.24)	(14.58)
Netback[5]	25.26	34.52	34.80	41.75	34.09
North Sea – Light Crude & Medium Crude Oil [4]					
Total production (mboe/d)	**72.0**	**73.2**	**57.0**	**56.5**	**64.6**
($/boe)					

Average price realized[2]	43.02	55.43	56.96	62.63	53.91
Royalties	—	—	—	—	—
Production costs	(7.72)	(6.68)	(6.98)	(8.62)	(7.46)
Netback[5]	35.30	48.75	49.98	54.01	46.45

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

(2) Average price realized is net of transportation costs, and before royalties.

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

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

(5) Netback is a non-GAAP financial measure. See the Advisories – Forward-Looking Information and Non-GAAP Financial Measures section of this AIF.

The following table provides the production volumes[1] on a working-interest basis, before royalties for each of Suncor's significant fields for the year ended December 31, 2016.

	SCO	Bitumen	Light & Medium Oil
	mbbls/d	mbbls/d	mbbls/d
Mining – Suncor	186.0	—	—
Mining – Syncrude	130.0	—	—
Firebag	72.2	88.4	—
MacKay River	—	27.6	—
Buzzard	—	—	46.0
GEAD	—	—	18.6
Hibernia	—	—	26.8
White Rose	—	—	10.9
Terra Nova	—	—	12.4
Total	388.2	116.0	114.7

(1) Volumes shown are actual volumes and may differ from the estimated volumes shown in the Reconciliation of Gross Reserves Tables.

Production Estimates

The table below outlines the production estimates for 2017 that are included in the estimates of gross proved reserves and gross probable reserves as at December 31, 2016. Total Proved plus Probable production estimates include 249.6 mbbls/d of SCO from Suncor's mining operations (excluding Syncrude), approximately 35% of total estimated production for 2017, 151.4 mbbls/d of SCO from Syncrude, approximately 21% of total estimated production for 2017, and 172.6 mbbls/d of SCO and bitumen from Firebag, approximately 24% of total estimated production for 2017.

	SCO		Bitumen		Light & Medium Crude Oil		Conventional Natural Gas		Total	
	(mbbls/d)		(mbbls/d)		(mbbls/d)		(mmcfe/d)		(mmboe/d)[1]	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Canada										
Proved	446	433	125	120	43	33	12	11	616	588
Probable	31	30	11	9	4	5	1	1	47	44
Proved Plus Probable	477	463	136	129	47	38	13	12	663	632
North Sea										
Proved	—	—	—	—	49	49	6	6	50	50
Probable	—	—	—	—	5	5	1	1	5	5
Proved Plus Probable	—	—	—	—	54	54	7	7	56	56
Total[1]										
Proved	446	433	125	120	93	82	18	17	666	638
Probable	31	30	11	9	9	10	2	2	52	49
Proved Plus Probable	477	463	136	129	102	92	20	19	718	688

(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, 2016. These commitments run through 2022 and beyond, and are primarily for conducting seismic programs and drilling exploration wells.

Country/Area ($ millions)	2017	2018	2019+	Total
Canada	—	40	46	86
North Sea	—	—	—	—
Other International	—	81	401	482

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 2016. A description of Suncor's use of such instruments is provided in the 2016 audited Consolidated Financial Statements and related MD&A for the year ended December 31, 2016.

Tax Horizon

In 2016, Suncor was subject to cash tax in the local jurisdictions related to earnings from its North Sea production, but was not cash taxable in Canada on the majority of its Canadian earnings. Based on projected future net earnings, Suncor is expected to be cash taxable on the majority of its Canadian earnings in 2017.

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. Current legislation is a matter of public record. All governments have the ability to change legislation, and 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. 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.

While the current U.S. administration has indicated its intention to renegotiate or withdraw from NAFTA, there have been no formal steps taken in this regard to date. As such, at this time, we are unable to predict whether such renegotiation or withdrawal will take place and, if so, what impact it may have.

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 for 2016 was 15% for active business income, including resource income. The average provincial income tax rate for Suncor in 2016 was 12%. The rate will decrease to 11.97% for 2017 as a result of a Quebec rate change enacted in the fourth quarter of 2016 which will decrease the Quebec rate from 11.9% to 11.5% over four years beginning effective January 1, 2017.

Other Jurisdictions

Operations in the U.S. are subject to the U.S. federal tax rate of 35% and a blended state rate of 2%.

Operations in the U.K. are subject to a tax rate of 40% (decreased from 50% in 2016), made up of the corporate income tax rate and the supplemental charge. In Norway, Suncor earns refundable tax credits related to eligible exploration spending at a rate of 78%.

Amounts presented in Suncor's 2016 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 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. 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.

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. 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 focused on achieving actual reduction goals and sustainable resource development across jurisdictions within North America.

As part of its ongoing business planning, Suncor assesses future costs associated with CO_2 emissions in its operations and the evaluation of future projects, based on the company's outlook for the carbon price under current and pending GHG regulations, using a price range of $30 to $65/tonne of CO_{2e} as a base case, applied against a range of policy design options. The company expects that environmental regulation will continue to evolve with a carbon price signal that balances economic, environmental and energy security objectives. Suncor will continue to review the impact of future carbon-constrained scenarios on its business strategy.

Some of the recent environmental regulations and initiatives related to climate change and GHG emissions are described below.

International Climate Change Agreements and Treaties

The common goal of the nearly 200 countries that have signed the Paris Agreement on climate change which came into force on November 4, 2016, is to hold global warming to "well below 2 degrees celsius" and to pursue efforts to limit the temperature increase to 1.5 degrees celsius above preindustrial levels. The Government of Canada set a goal to reduce GHG emissions economy-wide by 30% below 2005 levels by 2030.

Canadian Federal GHG Regulations

In furtherance of its commitments under the Paris Agreement, the federal government, along with the provincial and territorial leaders (excluding Manitoba and Saskatchewan), announced the Pan-Canadian – Framework on Clean Growth and Climate Change (PCF) in 2016.

Under the PCF, the federal government will require all jurisdictions to have a carbon price, starting at $10 per tonne in 2018 and rising by $10 per year to $50 per tonne in 2022. Jurisdictions can implement: (i) an explicit price-based system (such as the carbon tax adopted by British Columbia or the carbon levy and performance-based emissions system adopted in Alberta), or (ii) a cap-and-trade system (which has been adopted in Ontario and Quebec). Within these programs, provinces have discretion to manage competitiveness of their trade-exposed industries. The carbon pricing initiatives adopted in British Columbia, Alberta, Ontario and Quebec and their impact on Suncor are described in the Canadian Provincial GHG Regulations section below.

To complement carbon pricing, a clean fuel standard with the objective of achieving annual reductions of 30 Mt of GHG emissions by 2030 is being developed by the federal government. The standard would require reductions in the carbon footprint of the fuels supplied in Canada, based on life cycle analysis. The approach would not differentiate between crude oil types produced in or imported into Canada. This standard is expected to apply to a broad suite of fuels used in transportation, industry, homes and buildings; however, as the standard is currently under development, we are unable to predict the impact it will have.

Canadian Provincial GHG Regulations

In 2007, the Government of Alberta enacted the *Specified Gas Emitters Regulation* (SGER), which applies to facilities in Alberta with CO_{2e} emissions in excess of 100,000 tonnes per year. Suncor's Oil Sands Base plant, MacKay River plant, Firebag operations and the Edmonton refinery are currently subject to the SGER.

For the 2015 compliance year, Suncor earned a compliance credit of $10.9 million due to reliability and energy efficiency improvement across our operations with increased production. For the 2016 compliance year, Suncor estimates that it will earn a compliance credit of $1.6 million due to the planned turnaround at Upgrader 2, which increases emissions with reduced production, plus the reduced production from the Fort McMurray forest fires experienced in 2016. A 2017 forecast is unavailable pending government consultation with industry around policy design. Effective as of January 1, 2017, Alberta enacted the *Climate Leadership Act* (Climate Act). The Climate Act implements an economy-wide carbon levy on greenhouse gas emissions resulting from the combustion of fuels for heating and transportation on consumers and larger facilities and operations not otherwise subject to a

Carbon Competitiveness Regulation (CCR), which will replace the current SGER in 2018.

Under the CCR, facilities emitting over 100,000 tonnes per annum pay the economy-wide carbon levy, but in order to address competitiveness concerns of trade-exposed sectors like the oil sands, the CCR will provide facilities with output-based allocation credits up to a pre-determined performance benchmark. Further, the Alberta *Oil Sands Emissions Limit Act* (the OSELA) sets a limit of 100 Mt per year in the oil sands sector, excluding emissions from cogeneration and new upgrading capacity, allowing for continued growth and development while accelerating emissions reduction technology and operational optimization. The mechanics of implementation and enforcement of the OSELA are currently under review and it is not yet possible to predict the impact on Suncor.

The Province of British Columbia enacted a carbon tax in 2008, which is capped at $30/tonne of CO_{2e} through 2018. The carbon tax is applied on consumption. The purchaser or user of fuels pays the carbon tax, which is collected by Suncor and forwarded on to the government.

Quebec's and Ontario's cap-and-trade systems are linked to the Western Climate Initiative (WCI), an organization set up to help member states and provinces execute their cap-and-trade systems. Allowances and offsets are fungible across the WCI. In Quebec, 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 the Province. Suncor's Montreal refinery became subject to Quebec's cap-and-trade system for both its refinery GHG emissions and for emissions from transportation fuels effective January 1, 2015. For the 2015 compliance year, the cost of compliance for the Montreal refinery was $1 million. Similarly, the estimated compliance cost attributed to the Montreal refinery's stationary emissions for 2016 is $1 million. The majority of the compliance costs covering the emissions from transportation fuels are passed through to the customer. Beginning in 2017, Ontario facilities generating more than 25,000 tonnes of GHG emissions per year will be required to participate in the cap-and-trade program, which impacts Suncor's Sarnia refinery. Compliance will be similar to Quebec where Suncor's Sarnia refinery will be subject to both refinery GHG emissions and emissions from the use of transportation fuels.

U.S. GHG Regulations

The U.S. Environmental Protection Agency (U.S. EPA) has established a rule mandating that all large facilities (emitting greater than 25,000 tonnes of $CO2_e$ per year, which includes Suncor's refinery in Commerce City, Colorado) must report their GHG emissions. The new U.S. administration has expressed intent to review the mandate of the U.S. EPA. Additionally, the administration is reviewing the U.S.'s continued participation in the Paris Agreement. Suncor is monitoring these developments. The outcome of these reviews could lead to changes to GHG emissions regulations; however, the impact on Suncor, including its Commerce City, Colorado refinery, is unknown at this time.

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.

Land Use

In 2012, the Government of Alberta approved the Lower Athabasca Regional Plan (LARP). The LARP addresses land-use restrictions in the Lower Athabasca region of Alberta, which includes leases in Suncor's Oil Sands operations. 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 with 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 by 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 (SWQMF).** The SWQMF, released in February 2015, established weekly management triggers and water withdrawal limits that enable proactive management of mineable oil sands water used from the Athabasca River. Weekly water withdrawal limits reflect seasonal variability and may become more restrictive as flows in the river change. In addition, adaptive management triggers direct a management response process. As part of our commitment to the SWQMF, 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 m^3/s to 2 m^3/s. For our future operations at Fort Hills, we have on-site water storage and intend to manage water withdrawal as per the SWQMF.

- **Tailings Management Framework for Mineable Athabasca Oil Sands (TMF).** This framework, released in March 2015, provides oil sands miners with direction regarding the management of 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. The implementation of the TMF has occurred through the enactment of the Tailings Directive. The Tailings Directive uses fluid tailings volume triggers and a limit, as well as management actions such as a compliance levy and financial bonds through the Mine Financial Security Program (MFSP), to support the overarching policy objective of minimizing fluid tailings accumulation while balancing environmental, social and economic needs. The amount of any financial management actions, including compliance levies, and financial bonds through the MFSP have yet to be set. As such, at this time we are unable to predict what impact those amounts could have on Suncor.

  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 and convert a second to a fluid tailings treatment area. Under the TMF, Suncor is required to update the tailings management plans for our Oil Sands Base mine operations and Fort Hills facilities.

  The updated tailings management plan submitted for Suncor's Oil Sands Base mine operations is, and the plan for the Fort Hills project will be aligned with the company's principles on mine, tailings and reclamation: (i) establish outcomes that consider and incorporate the interests of Aboriginal communities and other stakeholders; (ii) establish stable closure landscapes integrated into the regional ecosystem; (iii) facilitate progressive reclamation by integrating mine, tailings and reclamation planning to ensure land is reclaimed permanently as early as practicable; (iv) manage life cycle costs and net environmental impacts; and (v) recognize the importance of flexibility and choices in order to incorporate innovations throughout the mine life.

Reclamation

The Government of Alberta's 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 2017 in relation to the TMF to include a tailings management action, integrated water management and tailings reclamation.

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.

Industry Collaboration Initiatives

Environmentally focused collaboration between companies and stakeholders is an important focus for the oil sands industry. Suncor is a founding member of Canada's Oil Sands Innovation Alliance (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 and assessment 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.

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 and other countries, 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 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 production from Oil Sands includes significant quantities of bitumen and SCO that trade at a discount to light and medium crude oil. Bitumen and SCO 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 SCO 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 and reserves.

Since the latter half of 2014, world oil prices have declined significantly. While world oil prices have moderately recovered from the low prices that have been experienced since the latter half of 2014, due in part to recently agreed upon quotas by OPEC and certain non-OPEC countries, there can be no assurances that this price recovery will continue or can be sustained. Failure by OPEC and these non-OPEC countries to meet or maintain their agreed upon quotas, in addition to the other factors discussed above, could cause world oil prices to decrease and such decrease could be significant and also lead to greater price volatility. A prolonged period of low and/or volatile commodity prices, particularly for crude oil, could have a material adverse effect on Suncor's business, financial condition, cash flows, reserves, and may also lead to the impairment of assets, or the cancellation or deferral of Suncor's growth projects.

Major Operational Incidents (Safety, Environmental and Reliability)

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 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, amongst others, fires (including forest fires), explosions, blow-outs, power outages, severe winter climate conditions and other extreme weather conditions, railcar incidents or derailments, the migration of harmful substances such as oil spills, gaseous leaks or a release of tailings into water systems, pollution and other environmental risks, and accidents, 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, including, amongst others, the following:

- Suncor's Oil Sands business is 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 interdependent component systems, and other risks inherent to oil sands (mining and in situ) operations;

- For Suncor's E&P 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, or the presence of hydrogen sulphide), premature declines of reservoirs, sour gas releases, uncontrollable flows of crude oil, natural gas or well fluids and other accidents;

- 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, reserves and cash flow. Refer also to Statement of Reserves Data and Other Oil and Gas Information – Significant Risk Factors and Uncertainties Affecting Reserves.

Government/Regulatory Policy and Compliance

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.

Before proceeding with most major projects, including significant changes to existing operations, Suncor must obtain various federal, provincial, state and municipal permits and regulatory approvals. Suncor must also obtain licences to operate certain assets. These processes can involve, among other things, Aboriginal and 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 or a third-party infrastructure project on which a portion of Suncor's business depends. 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, denial of 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.

Changes in government policy (including trade policies affecting energy resource exports) or regulation, or the interpretation thereof, or opposition to Suncor's projects or third-party pipeline and infrastructure projects that delays or prevents necessary permits or regulatory approvals could impact Suncor's operations and existing and planned projects. More recently, obtaining such approvals or permits has become more difficult due to increased public opposition and consultation, including Aboriginal consultation requirements. The result of these developments could 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, all of which could have a material adverse effect on Suncor's business, financial condition, reserves, results of operations and cash flow. Refer to the Industry Conditions section of this AIF.

Carbon Risk

Public support for climate change action and receptivity to new technologies has grown in recent years. Governments in Canada and around the world have responded to these shifting societal attitudes by adopting ambitious emissions reduction targets and supporting legislation, including measures relating to carbon pricing, clean energy and fuel standards, and alternative energy incentives and mandates. There has also been increased activism and public opposition to fossil fuels and oil sands in particular. Refer to the Industry Conditions – Environmental Regulation – Climate Change section of this AIF.

Existing and 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.

Environmental regulation, including regulation relating to climate change, could impact the demand for, formulation or quality of our products, or could require increased capital expenditures, operating expenses and distribution costs, which may or may not be recoverable in the marketplace. In addition, such regulatory changes could necessitate that Suncor develop new technologies. Such technology development could require a significant investment of capital and time and any delay in or failure to develop such technologies could prevent Suncor from obtaining regulatory approvals for projects or being able to successfully compete with other companies. Increasing environmental regulation in the jurisdictions in which Suncor operates may also make it difficult for Suncor to compete with companies operating in other jurisdictions with fewer or less costly regulations. The complexity and breadth of changes in environmental regulation make it extremely difficult to predict the potential impact to Suncor.

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 will be subject to incremental levies and taxes. There is also a risk that Suncor could face litigation initiated by third parties relating to climate change. In addition, the mechanics of implementation and enforcement of the OSELA are currently under review and it is not yet possible to predict the impact on Suncor. However, such impact could be material.

These developments and further such developments in the future could adversely impact the demand for Suncor's products, the ability of Suncor to maintain and grow its production and reserves, and Suncor's reputation and could have a material adverse effect on Suncor's business, financial condition, reserves, results of operations and cash flow.

Environmental Compliance

Tailings Management

There are risks associated with Suncor's tailings management plans, including with respect to joint arrangements in which Suncor has an interest. Each mine is required under the Tailings Directive to update its mine fluid tailings management plans. If those plans are not approved in the timelines anticipated or at all, the operators' ability to implement additional fluid tailings treatment facilities could be adversely impacted, which could result in reductions in production and lower volumes of treated tailings. If the mine exceeds certain compliance levels specified in the TMF, the applicable company could be subject to enforcement actions, including being required to curtail production, and financial consequences, including being subject to a compliance levy or being required to post additional security under the MFSP. The full impact of the TMF, including the financial consequences of exceeding compliance levels, is not yet fully known, as certain associated policies and regulations are still under

development. Such policies and regulations could also restrict the technologies that the company may employ for tailings management, which could adversely impact the company's business plans. There could also be risks if the company's tailings management operations fail to operate as anticipated. 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.

Alberta's Land-Use Framework (LARP)

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. 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. The changes in Suncor's business or operations required as a result of the LARP could have a material adverse effect on Suncor's business, financial condition, reserves, results of operations and cash flow.

Alberta Environment Water Licences

We currently rely on water 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. It is also possible that regional water management approaches may require water sharing agreements between stakeholders. 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 also a risk that future laws or changes to existing laws or regulations relating to water access could cause capital expenditures and operating expenses relating to water licence compliance to increase.

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.

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 costs, as well as affecting Suncor's bitumen blend marketing strategy.

Market access for oil sands production may be constrained by insufficient pipeline takeaway capacity, including as a result of the lack of new pipelines due to an inability to secure required approvals and negative public perception. There is a risk that constrained market access for oil sands production, growing inland production and refinery outages will potentially create 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. In the ordinary course of Suncor's business, Suncor collects and stores sensitive data, including intellectual property, proprietary business information and identifiable personal information of our employees and retail customers. Our operations are also dependent upon a large and complex information framework. We rely on industry accepted security measures and technology to protect Suncor's information systems and securely maintain confidential and proprietary information stored on our information systems, and have adopted a continuous process to identify, assess and manage threats to the company's information systems. Suncor's information security risk oversight is conducted by the Governance Committee. However, these measures and technology may not be adequate due to the increasing volume and sophistication of cyber threats. Suncor's information technology and infrastructure, including process control systems, may be vulnerable to attacks by hackers and cyberterrorists motivated by, among others, geopolitical, financial or activist reasons, or breached due to employee error, malfeasance or other disruptions. Any such attack or breach could compromise Suncor's networks and the information Suncor stores could be accessed, publicly disclosed, lost, stolen or compromised. Any such attack, breach, access, disclosure or loss of information could result in legal claims or proceedings, liability under laws that protect the privacy of personal information, regulatory penalties, disruptions to Suncor's operations,

decreased performance and production, increased costs, and damage to Suncor's reputation, which could have a material adverse effect on Suncor's business, financial condition, results of operations and cash flow. Although the company maintains a risk management program, which includes an insurance component that may provide coverage for certain impacts of attacks to or breaches of Suncor's information technology and infrastructure, including process control systems, such insurance does not address all such impacts and 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 and impacts of any such attack or breach.

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 start-up – 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 Asset Delivery and Execution 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.

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 for Suncor to deliver value to shareholders and stakeholders. These ambitious business objectives 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.

Joint Arrangement Risk

Suncor has entered into joint arrangements and other contractual arrangements with third parties with respect to certain of its projects, including arrangements where other entities operate assets in which Suncor has ownership or other interests. These joint arrangements include, amongst others, those with respect to Syncrude, Fort Hills, and operations in Suncor's E&P Canada and E&P International businesses. 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.

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, the British pound and the Norwegian krone. 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. As at December 31, 2016, the Canadian dollar strengthened slightly in relation to the U.S. dollar to 0.74 from 0.72 at the start of 2016. Exchange rate fluctuations 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. We are also exposed to changes in interest rates on derivative instruments used to manage the debt portfolio, including hedges of prospective new debt issuances. 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 balances and cash equivalents, cash flow provided by operating activities, available committed credit facilities, issuing commercial paper and, if needed, divesting of non-core assets and accessing capital markets. 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.

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. Short-term operational constraints on pipeline systems arising from pipeline interruption and/or increased supply of crude oil have occurred in the past and could occur in the future. 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.

Royalties and Taxes

Suncor is subject to royalties and taxes imposed by governments in numerous jurisdictions.

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 such events. The final determination of these events may have a material impact on the company's royalties expense.

An increase in Suncor's royalties expense, income taxes, property taxes, carbon taxes, tariffs, duties, border taxes, and other taxes and government-imposed compliance costs, could have a material adverse effect on Suncor's business, financial condition, reserves, 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 Public Officials Act* (Canada) and the United Kingdom *Bribery Act*;
- Renegotiation of contracts with government entities and quasi-government agencies;
- 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 or local 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, reserves 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 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 2016. Negotiations for a new collective agreement are in progress with Unifor at Suncor's Montreal refinery and at Terra Nova. 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, present 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. Although current commodity pricing has slowed certain larger projects in the short term, 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 cause 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 and Aboriginal Consultation

Aboriginal Peoples have claimed Aboriginal title and rights to portions of Western Canada. In addition, Aboriginal Peoples have filed claims against industry participants relating in part to land claims, which may affect our business.

The requirement to consult with Aboriginal Peoples in respect of oil and gas projects and related infrastructure has also increased in recent years. In addition, the Canadian federal government and the provincial government in Alberta have made a commitment to renew their relationships with Aboriginal Peoples of Canada. The federal government has stated it now fully supports the United Nations Declaration on the Rights of Indigenous Peoples (the Declaration) without qualification and that Canada intends "nothing less than to adopt and implement the Declaration in accordance with the Canadian Constitution." The Alberta government is also currently exploring how best to implement the principles and objectives of the Declaration in a way that is consistent with the Constitution and Alberta law. At this time, it is unclear how the Declaration will be adopted into Canadian law and the impact of the Declaration on the Crown's duty to consult with Aboriginal Peoples.

We are unable to assess the effect, if any, that any such land claims or consultation requirements with Aboriginal Peoples may have on our business, however, the impact may be material.

Litigation Risk

There is a risk that Suncor may be subject to litigation, and claims under such litigation 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 and reputational impacts 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, legislative requirements, 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 legislative requirements, the company's financial position, financing requirements for growth, cash flow and other factors. 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. The Board approved an increase in the quarterly dividend to $0.29 per share from $0.28 per share in the third quarter of 2015. In 2016, the Board of Directors approved a quarterly dividend of $0.29 per common share. Dividends are paid subject to applicable law, if, as and when declared by the Board.

Year ended December 31	**2016**	2015	2014
Cash dividends per common share ($)	**1.16**	1.14	1.02

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, 2016, there were 1,667,913,629 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 28, 2017. 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-	Negative	A-1 (low)	A-2
Dominion Bond Rating Service (DBRS)	A (low)	Stable	R-1 (low)	Not rated
Moody's Investors Service (Moody's)	Baa1	Stable	Not rated	P-2

S&P credit ratings on long-term debt are on a rating scale that ranges from AAA to D, representing the range of such securities rated from highest to lowest quality. A rating of A by S&P is the third highest of 10 categories. An obligation rated A is somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than obligations in higher rated categories (AA or AAA); however, the obligor's capacity to meet its financial commitment on the obligation is still strong. 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 than obligations in higher categories; the obligor's capacity to meet its financial commitment on the obligation is satisfactory.

DBRS credit ratings on long-term debt are on a rating scale that ranges from AAA to D, representing the range of such securities rated from highest to lowest. A rating of A by DBRS is the third highest of 10 categories and is assigned to debt securities considered to be of good credit quality, with the capacity for the payment of financial obligations being substantial, but of a lesser credit quality than an AA rating. Entities in the A category may be vulnerable to future events, but qualifying negative factors are considered manageable. All rating categories other than AAA and D also contain designations for (high) and (low). The assignment of a (high) or (low) designation within a rating category indicates relative standing within that category. The absence of either a (high) or (low) designation indicates the rating is in the middle of the 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 fall 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 judged to be medium grade and subject to moderate credit risk 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 debt 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, 2016 are as follows:

TSX

	Price Range (Cdn$)		Trading Volume
	High	Low	(000s)
2016			
January	35.90	27.32	87 386
February	34.13	28.40	89 088
March	36.84	32.49	79 975
April	37.47	34.96	60 510
May	36.70	32.69	76 092
June	36.52	33.49	111 953
July	37.27	34.51	55 683
August	36.84	33.76	55 386
September	36.83	34.01	58 001
October	42.14	36.03	69 867
November	43.54	39.03	65 844
December	44.67	42.28	57 683

For information in respect of options to purchase common shares of Suncor and common shares issued upon the exercise of options, see the Share-Based Compensation note to the 2016 audited Consolidated Financial Statements, which is incorporated by reference into this AIF and available on SEDAR at www.sedar.com.

On September 13, 2016, Suncor issued an aggregate of $700 million 3.00% medium term notes, series 5 due in 2026 and an aggregate of $300 million 4.34% medium term notes, series 5 due in 2046.

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[2][3] Washington, USA	Director since 2016 Independent	Patricia Bedient retired as executive vice president of Weyerhaeuser Company (Weyerhaeuser), one of the world's largest integrated forest products companies, effective July 1, 2016. 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 and Park Hotels and Resorts Inc. and also serves on 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 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 and received the lifetime achievement award.

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 Quebec and England. Ms. Côté is a director of Finning International Inc., the Royal Bank of Canada and TransContinental Inc. 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.

John D. Gass[1][4] 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 plc. 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.

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 & Risk 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, including her previous roles as chief executive officer and a director of Kaminak Gold Corporation, a mineral exploration company, vice president of Aber Resources, now Dominion Diamond Corp., and as founder and CEO of Stornoway Diamond Corp. Currently, Ms. Thomas is a director of Lucara Diamond Corp.

Steven W. Williams Alberta, Canada	Director since December 2011 Non-independent, management	Steve Williams is president and chief executive officer of Suncor. Steve's career with Suncor began in May 2002 when he was appointed executive vice president, corporate development and chief financial officer. He has also served as executive vice president, oil sands and chief operating officer. Steve has more than 39 years of international energy industry experience, including 18 years at Esso/Exxon. Steve holds a Bachelor of Science degree (Hons.) in chemical engineering from Exeter University and is a fellow of the Institution of Chemical Engineers. He is a graduate of the business economics program at Oxford University as well as the advanced management program at Harvard Business School. Steve has been named to the board of directors of the new Alcoa Corporation. He is a board member of the Business Council of Canada, a member of the Institute of Directors and a member of the McKinsey & Company Canada Advisory Council. He is one of 12 founding CEOs of COSIA and is a member of the advisory board of Canada's Ecofiscal Commission. Steve also serves as vice-chair of the Alberta Premier's Advisory Committee on the Economy. He is active in the community in the support of not-for-profit organizations including serving as co-chair of Indspire's "Building Brighter Futures" campaign. Steve attended the COP21 sessions as an official member of the Government of Canada delegation. In November 2015, he was chosen as the Canadian CEO of the Year by the Globe and Mail, Report on Business Magazine and, in July 2016, was named one of Alberta's 50 most influential people (Alberta Venture Magazine). In January 2017, he was named CEO of the Year by Alberta Oil Magazine.
Michael M. Wilson[(1)(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 vice 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
Steve Williams	Alberta, Canada	President and Chief Executive Officer
Mark Little	Alberta, Canada	President, Upstream
Eric Axford	Alberta, Canada	Executive Vice President, Business Services
Alister Cowan	Alberta, Canada	Executive Vice President and Chief Financial Officer
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

All executive officers have held positions with Suncor over the past five years with the exception of Mr. Cowan who, immediately prior to joining Suncor in 2014, was Chief Financial Officer of Husky Energy Inc.

As at February 24, 2017, 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 10 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 10 years, a director or executive officer of any company (including Suncor) that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets, other than: Mr. Benson, who 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 10 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. Bedient, Ms. Côté, Mr. D'Alessandro and Ms. McCaw. 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, Ms. Bedient 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)	**2016**	2015
Audit Fees	**5 758**	5 886
Audit-Related Fees	**415**	483
Tax Fees	**15**	15
All Other fees	**25**	25
Total	**6 213**	6 409

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, 2016, 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, 2016, (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, 2016.

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, 2016, 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 28, 2017 in respect of the company's Consolidated Financial Statements, which comprise the Consolidated Balance Sheets as at December 31, 2016 and December 31, 2015 and the Consolidated Statements of Comprehensive Income (Loss), Changes in Equity and Cash Flows for the years ended December 31, 2016 and December 31, 2015, and the related notes, and the report on internal control over financial reporting as at December 31, 2016. PricewaterhouseCoopers LLP has advised that they are independent with respect to the company within the meaning of the Rules of Professional Conduct of the 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 2017 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 2016 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; the performance of assets and equipment; capital efficiencies and cost-savings; applicable laws and government policies, including 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; the satisfaction by third parties of their obligations to Suncor; 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 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", "potential", "future", "opportunity", "would" and similar expressions.

Forward-looking statements in this AIF include references to:

Suncor's expectations about growth and other projects, the performance, costs and development of its assets, production volumes, and capital expenditures, including:

- *Statements about the Fort Hills mining project, including that first oil continues to remain on track for late 2017, that the company's share of the project costs is estimated to be $8.1 – $8.3 billion including the impacts of changes in the Canadian dollar since the project was sanctioned, that Suncor's share of Fort Hills' remaining project capital is between $1.6 and $1.8 billion, that the majority of the spend will occur in 2017 and will be completed within Suncor's existing capital guidance range, expected project activities in 2017 and 2018, and nameplate capacity of 194 mbbls/d (gross) of bitumen (99 mbbls/d net to Suncor);*
- *Statements about the Hebron project, including that first oil is expected in late 2017, planned gross oil production capacity of 150 mbbls/d (32 mbbls/d net to Suncor), that the project will include 1,200 mbbls of oil storage capacity and 52 well slots, expected project activities in 2017, and that Suncor's share of the post-sanction project cost estimate is approximately $2.8 billion (+/- 10%);*
- *Statements about the Rosebank project, including its design capacity of 100 mbbls/d (30 mbbls/d net to Suncor) of crude oil and 80 mmcf/d (24 mmcf/d net to Suncor) of natural gas, that it is expected to be complementary to Suncor's existing U.K. portfolio, and that if the project co-venturers approve the Rosebank project final investment decision and Suncor elects to participate, Suncor could pay additional consideration of up to US$165 million;*
- *Statements about the Oda project, including proposed development plans, that first oil is planned for 2019 with peak production expected to reach 35 mbbls/d (11 mbbls/d net to Suncor), and that Suncor's share of the post-sanction project cost estimate is approximately $270 million;*
- *Statements about Syncrude, including the expectation that the Syncrude co-owners' plan to develop two mining areas adjacent to the current mine would extend the life of Mildred Lake by a minimum of 10 years and that sustaining capital expenditures in 2017 will focus on planned maintenance and maintaining production capacity;*
- *The greenfield growth plan Suncor is evaluating, starting with Meadow Creek, and its replication strategy to build standardized surface facilities, well pads and infrastructure and the expectation that this plan will reduce facility capital expenditures;*
- *Suncor's belief that Voyageur South and Audet can be developed using mining techniques;*
- *Preliminary designs for the Joslyn North mining project plan for 160 mbbls/d of bitumen production (gross);*
- *The estimated cost of Suncor's remaining exploration work program commitment in Libya at December 31, 2016 of US$359 million;*
- *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;*
- *Expectations around exploration and appraisal initiatives in the North Sea, offshore Newfoundland and Labrador and offshore Nova Scotia, and drilling plans around these assets; and*

- *The expectation that the drilling of new well pairs and infill wells at Firebag and MacKay River will assist in maintaining production levels in future years.*

Also:

- *The participation agreements with the Fort McKay First Nation and Mikisew Cree First Nation for the sale of a combined 49% interest in the ETF development and the expectation that these transactions will close in the third quarter of 2017;*
- *Expectations around Suncor's new technology projects, including Suncor's commercial replication model for in situ extraction, PASS, AHS, oxy-fuel combustion, zero liquid discharge, ESEIEH, N-SOLV™, and SAGD LITE;*
- *Statements about Suncor's reserves, including reserves volumes, estimates of future net revenues, commodity price forecasts, exchange and interest rate expectations, and production estimates;*
- *Significant development activities and costs anticipated to occur or be incurred in 2017, including those identified under the Future Development Costs table in the Statement of Reserves Data and Other Oil and Gas Information section of this AIF, Suncor's belief that internally generated cash flows, existing and future credit facilities and, if needed, the divestiture of non-core assets and accessing capital markets will be sufficient to fund future development costs and that interest or other funding costs on their own would not make development of any property uneconomic, and the estimated value of work commitments;*
- *Estimated abandonment and reclamations costs;*
- *Anticipated royalty and income tax rates and the impact of these rates on Suncor; and*
- *Anticipated effects of and responses to environmental legislation, including climate change legislation, and Suncor's expected compliance costs.*

Forward-looking statements 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, or changes to, taxes, fees, royalties, duties and other government-imposed compliance costs; changes in environmental and other regulations and policies; 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 (including forest 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 technology and infrastructure 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, including climate change laws; risks and uncertainties associated with closing a transaction for the purchase or sale of a business, asset or 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; risks associated with land claims and Aboriginal consultation requirements; risks relating to litigation; 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 are discussed in further detail throughout this AIF, including under the heading Risk Factors, and the company's management's discussion and analysis dated March 1, 2017 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.

The forward-looking statements contained in this AIF are made as of the date of this AIF. Except as required by applicable securities laws, we assume no obligation to update publicly or otherwise revise any forward-looking statements or the foregoing risks and assumptions affecting such forward-looking statements, whether as a result of new information, future events or otherwise.

Non-GAAP Financial Measures – Netback

Netback is a non-GAAP financial measure. Netbacks are reconciled to GAAP measures in the Operating Metrics Reconciliation section of the Supplemental Financial and Operating Information within Suncor's Annual Report for the year ended December 31, 2016 and dated March 1, 2017.

Oil Sands Netbacks

Oil Sands operating netbacks are a non-GAAP measure, presented on a crude product and sales barrel basis, and are derived from the Oil Sands segmented statement of net earnings (loss), after adjusting for items not directly attributable to the revenues and costs associated with production and delivery. Management uses Oil Sands operating netbacks to measure crude product profitability on a sales barrel basis.

Exploration and Production (E&P) Netbacks

E&P netbacks are a non-GAAP measure, presented on an asset location and sales barrel basis, and are derived from the E&P segmented statement of net earnings (loss), after adjusting for items not directly attributable to the costs associated with production and delivery. Management uses E&P operating netbacks to measure asset profitability by location on a sales barrel basis.

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:

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

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

Constitution

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

Functions and Responsibilities

The Audit Committee has the following functions and responsibilities:

Internal Controls

1. Inquire as to the adequacy of the Corporation's system of internal controls of Suncor's business processes, 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 Standards for the Professional Practice of 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 direct and unrestricted access by management, the Internal Auditors and the external auditors to the Board of Directors.

Financial Reporting and other Public Disclosure

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

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

16. Review and approve the Corporation's interim consolidated financial statements and accompanying management's discussion and analysis ("MD&A"). Review and make recommendations to the Board of Directors on approval of the Corporation's annual audited 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 and processes 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 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 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 14, 2016

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 judgment on accounting standards;

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

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

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

(iii) Attest services required by statute or regulation;

(iv) Internal control reviews; and

(v) Assistance with and review of documents filed with the Canadian Securities administrators, the 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 of 1934, as amended. (See Appendix A for a summary of the prohibited services.)

IV. General Policy

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

- All services to be provided by the independent auditor will require specific pre-approval by the Audit Committee. The Audit Committee will not approve engaging the independent auditor for services 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 licenced, 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, 2016. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2016, 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 revenue (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, 2016, 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 Revenue (before income taxes, 10% discount rate, $ millions)			
			Audited	Evaluated	Reviewed	Total
GLJ Petroleum Consultants Ltd.	December 31, 2016	Oil Sands In Situ, Canada	—	23 270	—	23 270
GLJ Petroleum Consultants Ltd.	December 31, 2016	Oil Sands Mining, Canada	—	30 495	—	30 495
			—	53 765	—	53 765

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, March 1, 2017

"Caralyn P. Bennett"

Caralyn P. Bennett, P.Eng.
Executive Vice President, Chief Strategy Officer

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, 2016. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2016, 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 revenue (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, 2016, 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 Revenue (before income taxes, 10% discount rate, $ millions)			
			Audited	Evaluated	Reviewed	Total
Sproule Associates Limited	December 31, 2016	East Coast Canada, Newfoundland Offshore, Canada	—	6 037	—	6 037
Sproule Associates Limited	December 31, 2016	North America Onshore, Western Canada	—	28	—	28
Sproule International Limited	December 31, 2016	North Sea, United Kingdom	—	3 540	—	3 540
Sproule International Limited	December 31, 2016	North Sea, Norway	—	249	—	249
			—	9 854	—	9 854

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, March 1, 2017

"Cameron P. Six"

Cameron P. Six, P.Eng.
Chief Operating Officer and Director

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

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

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

"*Mark S. Little*"

MARK S. LITTLE
President, Upstream

"*James W. Simpson*"

JAMES W. SIMPSON
Chair of the Board of Directors

"*Michael W. O'Brien*"

MICHAEL W. O'BRIEN
Chair of the Audit Committee

March 1, 2017

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

suncor.com

UNDERTAKING AND CONSENT TO SERVICE OF PROCESS

A. Undertaking

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

B. Consent to Service of Process

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

DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROL OVER FINANCIAL REPORTING

See pages 77 and 78 of Exhibit 99-1 and page 66 of Exhibit 99-2.

ATTESTATION REPORT OF THE REGISTERED PUBLIC ACCOUNTING FIRM

See page 79 of Exhibit 99-1.

AUDIT COMMITTEE FINANCIAL EXPERT

See pages 77 and 78 of Annual Information Form.

CODE OF ETHICS

See page 27 of Annual Information Form.

FEES PAID TO PRINCIPAL ACCOUNTANT

See page 78 of Annual Information Form.

AUDIT COMMITTEE PRE-APPROVAL POLICIES

See Schedule "B" of Annual Information Form.

APPROVAL OF NON-AUDIT SERVICES

See Schedule "B" of Annual Information Form.

OFF-BALANCE SHEET ARRANGEMENTS

See page 51 of Exhibit 99-2.

TABULAR DISCLOSURE OF CONTRACTUAL OBLIGATIONS

See page 51 of Exhibit 99-2.

IDENTIFICATION OF THE AUDIT COMMITTEE

See page 77 of Annual Information Form.

SIGNATURES

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

SUNCOR ENERGY INC.

DATE: March 1, 2017

PER: /s/ ALISTER COWAN

Alister Cowan
Executive Vice President and Chief
Financial Officer

EXHIBIT INDEX

Exhibit No.	Description
99-1	Audited Consolidated Financial Statements of Suncor Energy Inc. for the fiscal year ended December 31, 2016
99-2	Management's Discussion and Analysis for the fiscal year ended December 31, 2016, dated March 1, 2017
99-3	Consent of PricewaterhouseCoopers LLP
99-4	Consent of GLJ Petroleum Consultants Ltd.
99-5	Consent of Sproule Associates Limited and Sproule International Limited
99-6	Certificate of the Chief Executive Officer Pursuant to Exchange Act Rules 13a-14(a) or 15d-14(a)
99-7	Certificate of the Chief Financial Officer Pursuant to Exchange Act Rules 13a-14(a) or 15d-14(a)
99-8	Certificate of the Chief Executive Officer Pursuant to 18 U.S.C. Section 1350, as Enacted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
99-9	Certificate of the Chief Financial Officer Pursuant to 18 U.S.C. Section 1350, as Enacted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
99-10	Supplementary Oil and Gas Disclosure

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DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROL OVER FINANCIAL REPORTING
ATTESTATION REPORT OF THE REGISTERED PUBLIC ACCOUNTING FIRM
AUDIT COMMITTEE FINANCIAL EXPERT
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EXHIBIT INDEX

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EXHIBIT 99-1

Audited Consolidated Financial Statements of Suncor Energy Inc. for the fiscal year ended December 31, 2016

MANAGEMENT'S STATEMENT OF RESPONSIBILITY FOR FINANCIAL REPORTING

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

The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles applicable to publically accountable enterprises, which is within the framework of International Financial Reporting Standards as issued by the International Accounting Standards Board incorporated into the CICA Handbook Part 1. They include certain amounts that are based on estimates and judgments.

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

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

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



Steven W. Williams
President and Chief Executive Officer



Alister Cowan
Executive Vice President and Chief Financial Officer

February 28, 2017

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

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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

2. Management has used the Committee of Sponsoring Organizations of the Treadway Commission (COSO) framework (2013) in Internal Control – Integrated Framework to evaluate the effectiveness of the company's internal control over financial reporting.

3. Management has assessed the effectiveness of the company's internal control over financial reporting as at December 31, 2016, and has concluded that such internal control over financial reporting was effective as of that date. Additionally, based on this assessment, management determined that there were no material weaknesses in internal control over financial reporting as at December 31, 2016. Because of inherent limitations, systems of internal control over financial reporting may not prevent or detect misstatements and even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

4. The effectiveness of the company's internal control over financial reporting as at December 31, 2016 has been audited by PricewaterhouseCoopers LLP, independent auditor, as stated in their report which appears herein.



Steven W. Williams
President and Chief Executive Officer



Alister Cowan
Executive Vice President and Chief Financial Officer

February 28, 2017

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders of
Suncor Energy Inc.

We have audited the accompanying Consolidated Balance Sheets of Suncor Energy Inc. as of December 31, 2016 and December 31, 2015 and the Consolidated Statements of Comprehensive Income (Loss), Cash Flows and Changes in Equity for each of the years in the two-year period ended December 31, 2016. We also have audited Suncor's internal control over financial reporting as of December 31, 2016, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Management is responsible for these Consolidated Financial Statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on these Consolidated Financial Statements and an opinion on Suncor Energy Inc.'s internal control over financial reporting based on our integrated audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the Consolidated Financial Statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the Consolidated Financial Statements included examining, on a test basis, evidence supporting the amounts and disclosures in the Consolidated Financial Statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall Consolidated Financial Statements presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that: (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Consolidated Financial Statements referred to above present fairly, in all material respects, the financial position of Suncor Energy Inc. as of December 31, 2016 and December 31, 2015 and the results of its operations and its cash flows for each of the years in the two-year period ended December 31, 2016 in conformity with International Financial Reporting Standards as issued by the International Accounting Standards Board. Also, in our opinion, Suncor Energy Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on criteria established in Internal Control – Integrated Framework (2013) issued by COSO.



Chartered Professional Accountants
Calgary, Alberta

February 28, 2017

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

For the years ended December 31 ($ millions)	Notes	2016	2015
Revenues and Other Income			
Operating revenues, net of royalties	6	**26 807**	29 208
Other income	9	**161**	472
		26 968	29 680
Expenses			
Purchases of crude oil and products		**9 877**	11 590
Operating, selling and general	10 and 27	**9 150**	8 607
Transportation		**1 072**	1 085
Depreciation, depletion, amortization and impairment	11 and 18	**6 117**	7 500
Exploration		**289**	478
Gain on disposal of assets	38	**(68)**	(110)
Financing expenses	12	**445**	2 557
		26 882	31 707
Earnings (Loss) before Income Taxes		**86**	(2 027)
Income Taxes	13		
Current		**153**	892
Deferred		**(512)**	(924)
		(359)	(32)
Net Earnings (Loss)		**445**	(1 995)
Net Earnings (Loss) Attributable to:			
Common Shareholders		**434**	(1 995)
Non-controlling interest	7	**11**	—
		445	(1 995)
Other Comprehensive (Loss) Income			
Items Reclassified to Earnings:			
Realized gain on assets available for sale, net of income taxes of $13	38	**—**	(85)
Items That May be Subsequently Reclassified to Earnings:			
Foreign currency translation adjustment		**(258)**	846
Items That Will Not be Reclassified to Earnings:			
Actuarial (loss) gain on employee retirement benefit plans, net of income taxes of $5		**(24)**	212
Other Comprehensive (Loss) Income		**(282)**	973

Total Comprehensive Income (Loss)		**163**	(1 022)
Per Common Share (dollars)	14		
Net earnings (loss) – basic and diluted		**0.28**	(1.38)
Net earnings (loss) – attributable to common shareholders – basic and diluted		**0.27**	(1.38)
Cash dividends		**1.16**	1.14

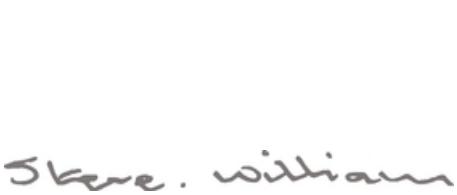
The accompanying notes are an integral part of the consolidated financial statements.

CONSOLIDATED BALANCE SHEETS

($ millions)	Notes	**December 31 2016 (see note 7)**	December 31 2015
Assets			
Current assets			
Cash and cash equivalents	15	**3 016**	4 049
Accounts receivable		**3 182**	2 751
Inventories	17	**3 240**	3 090
Income taxes receivable		**376**	538
Assets held for sale	39	**1 205**	—
Total current assets		**11 019**	10 428
Property, plant and equipment, net	18, 34, 35, 36 and 37	**71 259**	61 151
Exploration and evaluation	19	**2 038**	1 681
Other assets	20	**1 248**	1 153
Goodwill and other intangible assets	21	**3 075**	3 079
Deferred income taxes	13	**63**	35
Total assets		**88 702**	77 527
Liabilities and Shareholders' Equity			
Current liabilities			
Short-term debt	22	**1 273**	747
Current portion of long-term debt	22	**54**	70
Accounts payable and accrued liabilities		**5 588**	5 306
Current portion of provisions	25	**781**	769
Income taxes payable		**224**	244
Liabilities associated with assets held for sale	39	**197**	—
Total current liabilities		**8 117**	7 136
Long-term debt	22	**16 103**	14 486
Other long-term liabilities	23	**2 067**	1 573
Provisions	25	**6 542**	5 339
Deferred income taxes	13	**11 243**	9 954
Equity		**44 630**	39 039
Total liabilities and shareholders' equity		**88 702**	77 527

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

Approved on behalf of the Board of Directors:



Steven W. Williams
Director



Michael W. O'Brien
Director

February 28, 2017

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the years ended December 31 ($ millions)	Notes	2016	2015
Operating Activities			
Net earnings (loss)		**445**	(1 995)
Adjustments for:			
Depreciation, depletion, amortization and impairment		**6 117**	7 500
Deferred income taxes		**(512)**	(924)
Accretion		**269**	197
Unrealized foreign exchange (gain) loss on U.S. dollar denominated debt		**(458)**	1 967
Change in fair value of financial instruments and trading inventory		**(7)**	87
Gain on disposal of assets		**(68)**	(110)
Loss on extinguishment of long-term debt	12	**99**	—
Share-based compensation		**142**	18
Exploration		**204**	255
Settlement of decommissioning and restoration liabilities		**(269)**	(302)
Other		**26**	113
(Increase) decrease in non-cash working capital	16	**(308)**	78
Cash flow provided by operating activities		**5 680**	6 884
Investing Activities			
Capital and exploration expenditures		**(6 582)**	(6 667)
Cash acquired from Canadian Oil Sands Limited	7	**109**	—
Acquisitions	8, 34, 35 and 36	**(1 014)**	(360)
Proceeds from disposal of assets		**229**	277
Other investments		**(25)**	(18)
(Increase) in non-cash working capital	16	**(224)**	(3)
Cash flow used in investing activities		**(7 507)**	(6 771)
Financing Activities			
Net change in short-term debt		**531**	(203)
Repayment of long-term debt		**(1 693)**	(55)
Issuance of long-term debt	12	**993**	—
Issuance of common shares under share option plans		**133**	95
Issuance (purchase) of common shares	26	**2 782**	(43)
Dividends paid on common shares		**(1 877)**	(1 648)
Cash flow provided by (used in) financing activities		**869**	(1 854)

Decrease in Cash and Cash Equivalents	**(958)**	(1 741)
Effect of foreign exchange on cash and cash equivalents	**(75)**	295
Cash and cash equivalents at beginning of year	**4 049**	5 495
Cash and Cash Equivalents at End of Year	**3 016**	4 049

Supplementary Cash Flow Information		
Interest paid	**992**	881
Income taxes (received) paid	**(161)**	1 424

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

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

($ millions)	Notes	Share Capital	Contributed Surplus	Accumulated Other Comprehensive Income	Non-Controlling Interest	Retained Earnings	Total	Number of Common Shares (thousands)
At December 31, 2014		19 311	609	504	—	21 179	41 603	1 444 119
Net loss		—	—	—	—	(1 995)	(1 995)	—
Foreign currency translation adjustment		—	—	846	—	—	846	—
Realized gain on disposal of assets available for sale, net of income taxes of $13	38	—	—	(85)	—	—	(85)	—
Actuarial gain on employee retirement benefit plans, net of income taxes of $75		—	—	—	—	212	212	—
Total comprehensive income (loss)		—	—	761	—	(1 783)	(1 022)	—
Issued under share option plans		125	(20)	—	—	—	105	3 124
Issued under dividend reinvestment plan		47	—	—	—	(47)	—	—
Purchase of common shares for cancellation	26	(17)	—	—	—	(26)	(43)	(1 230)
Share-based compensation		—	44	—	—	—	44	—
Dividends paid on common shares		—	—	—	—	(1 648)	(1 648)	—
At December 31, 2015		19 466	633	1 265	—	17 675	39 039	1 446 013
Net earnings		—	—	—	**11**	**434**	**445**	—
Foreign currency translation adjustment		—	—	**(258)**	—	—	**(258)**	—
Actuarial loss on employee retirement benefit plans, net of income taxes of $5		—	—	—	—	**(24)**	**(24)**	—
Total comprehensive (loss) income		—	—	**(258)**	**11**	**410**	**163**	—
Issued under share option plans		**216**	**(84)**	—	—	—	**132**	**3 983**
Issued for cash, net of income taxes of $26	26	**2 808**	—	—	—	—	**2 808**	**82 225**
Issued for the acquisition of Canadian Oil Sands Limited	7	**3 154**	—	—	**1 172**	—	**4 326**	**98 814**
Equity transactions to eliminate non-controlling interest in Canadian Oil Sands Limited	7	**1 298**	—	—	**(1 183)**	**(115)**	—	**36 879**

Share-based compensation	—	39	—	—	—	39	—
Dividends paid on common shares	—	—	—	—	(1 877)	(1 877)	—
At December 31, 2016	**26 942**	**588**	**1 007**	**—**	**16 093**	**44 630**	**1 667 914**

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

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. REPORTING ENTITY AND DESCRIPTION OF THE BUSINESS

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

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

2. BASIS OF PREPARATION

(a) Statement of Compliance

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

Suncor's accounting policies are based on IFRS issued and outstanding for all periods presented in these consolidated financial statements. These consolidated financial statements were approved by the Board of Directors on February 28, 2017.

Comparative figures have been reclassified to conform to the current year financial statement presentation for the revenues and expenses for the company's ethanol business that is presented in the Refining and Marketing segment, and was previously presented in the Corporate, Energy Trading and Eliminations segment (note 6).

(b) Basis of Measurement

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

(c) Functional Currency and Presentation Currency

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

(d) Use of Estimates, Assumptions and Judgments

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

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

(a) Principles of Consolidation

The company consolidates its interests in entities it controls. Control comprises the power to govern an entity's financial and operating policies to obtain benefits from its activities, and is a matter of judgment. All intercompany balances and transactions are eliminated in preparing the consolidated financial statements.

Certain of the company's activities are conducted through joint operations, and the consolidated financial statements reflect the company's proportionate share of the joint operations' assets, liabilities, revenues and expenses, on a line-by-line basis.

(b) Joint Arrangements

Joint arrangements represent arrangements in which two or more parties have joint control established by a contractual agreement. Joint control only exists when decisions about the activities that most significantly affect the returns of the investee are unanimous. Joint arrangements can be classified as either a joint operation or a joint venture. The classification depends on the contractual rights and obligations of each investor, rather than the legal structure of the joint arrangement.

Where the company has rights to the assets and obligations for the liabilities of a joint arrangement, such arrangement is classified as a joint operation and the company's share of the assets, liabilities, revenues and expenses is included in the consolidated financial statements.

Where the company has rights to the net assets of an arrangement, the arrangement is classified as a joint venture and accounted for using the equity method of accounting. Under the equity method, the company's initial investment is recognized at cost and subsequently adjusted for the company's share of the joint venture's income or loss, less distributions received.

(c) Foreign Currency Translation

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

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

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

(d) Revenues

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

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

(e) Cash and Cash Equivalents

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

(f) Inventories

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

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

(g) Assets Held for Sale

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

(h) Exploration and Evaluation Assets

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

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

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

(i) Property, Plant and Equipment

Property, Plant and Equipment are initially recorded at cost.

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

The costs to construct, install and commission, or acquire, oil and gas production equipment, including oil sands upgraders, extraction plants, mine equipment, processing and power generation facilities, utility plants, and all renewable energy, refining, and marketing assets, are capitalized as plant and equipment within Property, Plant and Equipment.

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

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

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

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

(j) Depreciation, Depletion and Amortization

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

associated with oil sands mines, which are depreciated on a straight-line basis over the life of the mine, and property acquisition costs, which are depleted over proved reserves.

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

Costs to develop oil and gas properties other than certain oil sands mining assets, including costs of dedicated infrastructure, such as well pads and wellhead equipment, are depleted on a unit-of-production basis over proved developed reserves. A portion of these costs may not be depleted if they relate to undeveloped reserves. Costs related to offshore facilities are depleted over proved and probable reserves. Costs to develop and construct oil sands mines are depreciated on a straight-line basis over the life of the mine.

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

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

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

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

(k) Goodwill and Other Intangible Assets

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

Other intangible assets include acquired customer lists and brand value.

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

(l) Impairment of Assets

Non-Financial Assets

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

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

Impairments may be reversed for all CGUs and individual assets, other than goodwill, if there has been a change in the estimates and judgments used to determine the asset's recoverable amount. If such indication exists, the carrying amount

of the CGU or asset is increased to its revised recoverable amount which cannot exceed the carrying amount that would have been determined, net of depletion, depreciation and amortization, had no impairment been recognized.

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

Financial Assets

At each reporting date, the company assesses whether there is evidence that financial assets that are carried at amortized cost are impaired. If a financial asset carried at amortized cost is impaired, the impairment is recognized in Operating, Selling and General expense.

(m) Provisions

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

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

(n) Income Taxes

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

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

(o) Pensions and Other Post-Retirement Benefits

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

The cost of pension benefits earned by employees in the defined contribution pension plan is expensed as incurred. The cost of defined benefit pension plans and other post-retirement benefits are actuarially determined using the projected unit credit method based on present pay levels and management's best estimates of demographic and financial assumptions. Pension benefits earned during the current year are recorded in Operating, Selling and General expense. Interest costs on the net unfunded obligation are recorded in Financing Expenses. Any actuarial gains or losses are recognized immediately through Other Comprehensive Income and transferred directly to Retained Earnings.

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

(p) Share-Based Compensation Plans

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

Share-based compensation awards that settle in cash or have the option to settle in cash or shares are accounted for as cash-settled plans. These are measured at fair value each reporting period using the Black-Scholes options pricing model. The expense is recognized over the vesting period, with a corresponding adjustment to liabilities. When awards are

surrendered for cash, the cash settlement paid reduces the outstanding liability. When awards are exercised for common shares, consideration paid by the holder and the previously recognized liability associated with the options are recorded to Share Capital.

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

(q) Financial Instruments

The company classifies its financial instruments into one of the following categories: fair value through profit or loss; assets available for sale; held-to-maturity investments; loans and receivables, and financial liabilities measured at amortized cost. All financial instruments are initially recognized at fair value on the balance sheet, net of any transaction costs except for financial instruments classified as fair value through profit and loss, where transaction costs are expensed as incurred. Subsequent measurement of financial instruments is based on their classification. The company classifies derivative financial instruments as fair value through profit and loss, cash and cash equivalents and accounts receivable as loans and receivables, financial instruments included in other assets as available for sale, and accounts payable and accrued liabilities, debt, and other long-term liabilities as other financial liabilities.

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

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

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

(r) Hedging Activities

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

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

(s) Share Capital

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

(t) Dividend Distributions

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

(u) Earnings per Share

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

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

(v) Emissions Obligations

Emissions obligations are measured at the weighted average cost per unit of emissions expected to be incurred in the compliance period. Emissions are treated as a cost of production and, as such, are recognized in Operating, Selling and General expense in the period in which the emissions occurred.

Purchases of emissions rights are recognized as Other Assets on the balance sheet and are measured at historical cost. Emissions rights received by way of grant are recorded at a nominal amount.

4. SIGNIFICANT ACCOUNTING ESTIMATES AND JUDGMENTS

The preparation of financial statements in accordance with IFRS requires management to make estimates and judgments that affect reported assets, liabilities, revenues, expenses, gains, losses, and disclosures of contingencies. These estimates and judgments are subject to change based on experience and new information. The financial statement areas that require significant estimates and judgments are as follows:

Oil and Gas Reserves

Measurements of depletion, depreciation, impairment and decommissioning and restoration obligations are determined in part based on the company's estimate of oil and gas reserves. The estimation of reserves is an inherently complex process and involves the exercise of professional judgment. All reserves have been evaluated at December 31, 2016 by independent qualified reserves evaluators. Oil and gas reserves estimates are based on a range of geological, technical and economic factors, including projected future rates of production, projected future commodity prices, engineering data, and the timing and amount of future expenditures, all of which are subject to uncertainty. Estimates reflect market and regulatory conditions existing at December 31, 2016, which could differ significantly from other points in time throughout the year, or future periods. Changes in market and regulatory conditions and assumptions can materially impact the estimation of net reserves.

Oil and Gas Activities

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

Exploration and Evaluation Costs

Certain exploration and evaluation costs are initially capitalized with the intent to establish commercially viable reserves. The company is required to make judgments about future events and circumstances and applies estimates to assess the economic viability of extracting the underlying resources. The costs are subject to technical, commercial and management review to confirm the continued intent to develop the project. Level of drilling success or changes to project economics, resource quantities, expected production techniques, production costs and required capital expenditures are important judgments when making this determination. Management uses judgment to determine when these costs are reclassified to Property, Plant and Equipment based on several factors including the existence of reserves, appropriate approvals from regulatory bodies and the company's internal project approval process.

Determination of Cash Generating Units (CGUs)

A CGU is the lowest grouping of integrated assets that generate identifiable cash inflows that are largely independent of the cash inflows of other assets or groups of assets. The allocation of assets into CGUs requires significant judgment and

interpretations with respect to the integration between assets, the existence of active markets, similar exposure to market risks, shared infrastructures, and the way in which management monitors the operations.

Asset Impairment and Reversals

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

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

Decommissioning and Restoration Costs

The company recognizes liabilities for the future decommissioning and restoration of Exploration and Evaluation assets and Property, Plant and Equipment. Management applies judgment in assessing the existence and extent as well as the expected method of reclamation of the company's decommissioning and restoration obligations at the end of each reporting period. Management also uses judgment to determine whether the nature of the activities performed is related to decommissioning and restoration activities or normal operating activities.

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

Employee Future Benefits

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

Other Provisions

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

Income Taxes

Management evaluates tax positions, annually or when circumstances require, which involves judgment and could be subject to differing interpretations of applicable tax legislation. The company recognizes a tax provision when a payment to tax authorities is considered probable. However, the results of audits and reassessments and changes in the interpretations of standards may result in changes to those positions and, potentially, a material increase or decrease in the company's assets, liabilities and net earnings.

Deferred Income Taxes

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

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

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

Fair Value of Financial Instruments

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

Functional Currency

The designation of the functional currency of the company and each of its subsidiaries is a management judgment based on the composition of revenue and costs in the locations in which it operates.

Fair Value of Share-Based Compensation

The fair values of equity-settled and cash-settled share-based payment awards are estimated using the Black-Scholes options pricing model. These estimates depend on certain assumptions, including share price, volatility, risk-free interest rate, the term of the awards, the forfeiture rate and the annual dividend yield, which, by their nature, are subject to measurement uncertainty.

5. RECENTLY ANNOUNCED ACCOUNTING PRONOUNCEMENTS

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

Statement of Cash Flows

In January 2016, the IASB issued an amendment to IAS 7 *Statement of Cash Flows*. The amendment to IAS 7 requires additional disclosures for changes in liabilities arising from financing activities. This includes changes arising from cash flows, such as drawdowns and repayments of borrowings, and non-cash changes, such as acquisitions, disposals and unrealized exchange differences. The amendment is effective for fiscal years beginning on or after January 1, 2017, and is applied on a prospective basis. The adoption of this standard is not expected to have a material impact on the company's disclosures.

Revenue from Contracts with Customers

In May 2014, the IASB issued IFRS 15 *Revenue from Contracts with Customers.* It replaces existing revenue recognition guidance and provides a single, principles-based five-step model to be applied to all contracts with customers. Retrospective application of this standard is effective for fiscal years beginning on or after January 1, 2018, with earlier application permitted. The adoption of this standard is not expected to have a material impact on the company's disclosure.

Financial Instruments: Recognition and Measurement

In July 2014, IFRS 9 *Financial Instruments* was issued as a complete standard, including the requirements previously issued related to classification and measurement of financial assets and liabilities, and additional amendments to introduce a new expected loss impairment model for financial assets including credit losses. Retrospective application of this standard with certain exemptions is effective for fiscal years beginning on or after January 1, 2018, with earlier application permitted. The adoption of this standard is not expected to have a material impact on the company's disclosure.

Leases

In January 2016, the IASB issued IFRS 16 *Leases* which replaces the existing leasing standard (IAS 17 *Leases*) and requires the recognition of most leases on the balance sheet. IFRS 16 effectively removes the classification of leases as either finance or operating leases and treats all leases as finance leases for lessees with exemptions for short-term leases where the term is twelve months or less and for leases of low-value items. The accounting treatment for lessors remains essentially unchanged, with the requirement to classify leases as either finance or operating remaining. IFRS 16 is effective January 1, 2019, with earlier application permitted. IFRS 16 is expected to significantly increase the company's long-term assets and liabilities, increase depreciation, depletion, amortization and impairment, increase financing expense and reduce operating, selling and general expense. The company has developed a transition team to assess the impact of IFRS 16 and implement the necessary changes to accounting systems, processes and internal controls as a result of the new standard.

Share-based payments

In June 2016, the IASB issued the final amendments to IFRS 2 *Share-based payments* that clarify the classification and measurement of share-based payment transactions. This includes the effect of vesting and non-vesting conditions on the measurement of cash-settled share-based payments, share-based payment transactions with a net settlement feature for withholding tax obligations, and a modification to the terms and conditions of a share-based payment that changes the classification of the transaction from cash-settled to equity-settled. The amendments are to be applied prospectively and are effective for annual periods beginning on or after January 1, 2018, with earlier application permitted. The company is currently assessing the impact of this standard.

6. SEGMENTED INFORMATION

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

- Oil Sands includes the company's operations in the Athabasca oil sands in Alberta to develop and produce synthetic crude oil and related products, through the recovery and upgrading of bitumen from mining and in situ operations. This segment also includes the company's joint interest in the Fort Hills mining project as well as its ownership interest in the Syncrude oil sands mining and upgrading joint operation, located near Fort McMurray, Alberta. The individual operating segments related to mining operations, in situ, Fort Hills and Syncrude have been aggregated into one reportable segment (Oil Sands) due to the similar nature of their business activities, including the production of bitumen, and that they operate in the same geographic area and regulatory environment.

- Exploration and Production includes offshore activity in East Coast Canada, with interests in the Hibernia, Terra Nova, White Rose and Hebron oilfields, the exploration and production of crude oil and natural gas in the United Kingdom (U.K.), Norway, Libya and Syria, and exploration and production of natural gas and natural gas liquids in Western Canada. Due to unrest in Syria, the company has declared force majeure under its contractual obligations, and Suncor's operations in Syria have been suspended indefinitely. Due to political unrest in Libya, the company's production remained substantially shut in through the majority of 2016.

- Refining and Marketing includes the refining of crude oil products, and the distribution and marketing of these and other purchased products through retail stations located in Canada and the United States (U.S.), as well as a lubricants plant located in Eastern Canada that is currently classified as Assets Held for Sale (note 39).

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

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

Comparative figures have been reclassified to conform to the current year financial statement presentation for the revenues and expenses for the company's ethanol business that is presented in the Refining and Marketing segment, and was previously presented in Corporate, Energy Trading and Eliminations. The reclassification resulted in an increase in net earnings for the Refining and Marketing segment and an increase in net loss for Corporate, Energy Trading and Eliminations of $40 million for the year ended December 31, 2015.

For the years ended December 31	Oil Sands		Exploration and Production		Refining and Marketing		Corporate, Energy Trading and Eliminations		Total	
($ millions)	**2016**	2015	**2016**	2015	**2016**	2015	**2016**	2015	**2016**	2015
Revenues and Other Income						(restated)		(restated)		
Gross revenues	**7 229**	7 174	**2 329**	2 524	**17 459**	19 839	**55**	52	**27 072**	29 589
Intersegment revenues	**2 293**	2 158	**115**	88	**108**	43	**(2 516)**	(2 289)	**—**	—
Less: Royalties	**(52)**	(114)	**(213)**	(267)	**—**	—	**—**	—	**(265)**	(381)
Operating revenues, net of royalties	**9 470**	9 218	**2 231**	2 345	**17 567**	19 882	**(2 461)**	(2 237)	**26 807**	29 208
Other income	**26**	146	**45**	150	**16**	86	**74**	90	**161**	472
	9 496	9 364	**2 276**	2 495	**17 583**	19 968	**(2 387)**	(2 147)	**26 968**	29 680
Expenses										
Purchases of crude oil and products	**548**	319	**—**	3	**11 754**	13 571	**(2 425)**	(2 303)	**9 877**	11 590
Operating, selling and general	**5 777**	5 220	**483**	502	**2 203**	2 219	**687**	666	**9 150**	8 607
Transportation	**666**	645	**86**	98	**366**	388	**(46)**	(46)	**1 072**	1 085
Depreciation, depletion, amortization and impairment	**3 864**	3 583	**1 381**	3 106	**702**	685	**170**	126	**6 117**	7 500
Exploration	**30**	120	**259**	358	**—**	—	**—**	—	**289**	478
(Gain) loss on disposal of assets	**(33)**	8	**—**	(5)	**(35)**	(109)	**—**	(4)	**(68)**	(110)
Financing expenses	**234**	150	**82**	82	**10**	(14)	**119**	2 339	**445**	2 557
	11 086	10 045	**2 291**	4 144	**15 000**	16 740	**(1 495)**	778	**26 882**	31 707
(Loss) Earnings before Income Taxes	**(1 590)**	(681)	**(15)**	(1 649)	**2 583**	3 228	**(892)**	(2 925)	**86**	(2 027)
Income Taxes										
Current	**(363)**	3	**301**	344	**681**	943	**(466)**	(398)	**153**	892
Deferred	**(78)**	172	**(506)**	(1 235)	**12**	(21)	**60**	160	**(512)**	(924)
	(441)	175	**(205)**	(891)	**693**	922	**(406)**	(238)	**(359)**	(32)
Net (Loss) Earnings	**(1 149)**	(856)	**190**	(758)	**1 890**	2 306	**(486)**	(2 687)	**445**	(1 995)
Capital and Exploration Expenditures	**4 724**	4 181	**1 139**	1 459	**685**	821	**34**	206	**6 582**	6 667

Geographical Information

Operating Revenues, net of Royalties

($ millions)	**2016**	2015
Canada	**21 555**	23 147

United States	**3 695**	4 246
Other foreign	**1 557**	1 815
	26 807	29 208

Non-Current Assets[1]

($ millions)	**Dec 31 2016**	Dec 31 2015
Canada	**74 906**	61 592
United States	**1 509**	1 852
Other foreign	**1 205**	3 620
	77 620	67 064

(1) Excludes deferred income tax assets.

7. ACQUISITION OF CANADIAN OIL SANDS LIMITED (COS)

On February 5, 2016, Suncor obtained control of Canadian Oil Sands Limited (COS) by acquiring 73% of COS' outstanding common shares in exchange for 0.28 of a Suncor share per COS share tendered. The acquisition resulted in the issuance of 98.9 million Suncor common shares, which had a fair value of $31.88 per share based on the closing price on the TSX on the acquisition date.

COS owned a 36.74% interest in the Syncrude joint operation. Suncor acquired COS to benefit from operating synergies and economies of scale expected from combining the two companies' ownership interests in Syncrude.

Purchase Price Consideration

Number of COS common shares tendered (millions)	353.3
Multiplied by share exchange ratio	0.28
Number of Suncor common shares issued (millions)	98.9
Share price on acquisition date	$31.88
Fair value of consideration ($ millions)	**3 154**

On February 22, 2016, and March 21, 2016, Suncor acquired the remaining outstanding 131.3 million COS shares on the same terms as the initial acquisition, resulting in the issuance of an additional 36.7 million Suncor common shares, which resulted in a total acquisition price of $4.452 billion. The estimated fair values of the net assets acquired were not adjusted to reflect the changes in Suncor's share price on the subsequent transaction dates.

Purchase Price Allocation

The acquisition has been accounted for as a business combination using the acquisition method whereby the net assets acquired and the liabilities assumed are recorded at fair value, except for the employee future benefit liability which is measured as the present value of the net obligation. The purchase price allocation is based on management's best estimates of fair values of COS' assets and liabilities as at February 5, 2016.

($ millions)

Cash	109
Accounts receivable	231
Inventory	135
Other assets	105
Property, plant and equipment	9 476
Exploration and evaluation	602
Total assets acquired	**10 658**
Accounts payable and other liabilities	(375)
Long-term debt	(2 639)
Employee future benefits	(323)
Decommissioning provision	(1 169)
Deferred income taxes	(1 826)
Total liabilities assumed	**(6 332)**
Net assets of Canadian Oil Sands	**4 326**
Non-controlling interest	(1 172)
Net assets acquired	**3 154**

The fair values of cash, accounts receivable and other current assets, and accounts payable and other liabilities approximate their carrying values due to the short-term maturity of the instruments. The fair values of crude inventory and long-term debt were determined using quoted prices and rates from available pricing sources. The fair value of materials and supplies inventory approximates book value due to short-term turnover rates. The fair values of property, plant and equipment, and the decommissioning provision were determined using an expected future cash flow approach. Key assumptions used in the calculations were discount rates, future commodity prices and costs, timing of development activities, projections of oil reserves, and cost estimates to abandon and reclaim the mine and facilities.

The following table summarizes the fair value of COS debt acquired by Suncor.

($ millions)	February 5, 2016
Fixed-term debt, redeemable at the option of the company	
7.75% Notes, due 2019 (US$500)	755
7.90% Notes, due 2021 (US$250)	389
4.50% Notes, due 2022 (US$400)	515
8.20% Notes, due 2027 (US$74)	114
6.00% Notes, due 2042 (US$300)	316
Total Notes	2 089
Credit facility	550

Total long-term debt	**2 639**

During the second quarter of 2016 the company repurchased US$688 million of debt acquired through the acquisition of COS. The company also repaid approximately $600 million of the credit facility acquired in the COS transaction.

The non-controlling interest (NCI) was initially measured at the NCI's proportionate share of the net identifiable assets acquired. The subsequent transactions on February 22, 2016, and March 21, 2016, were accounted for as equity transactions with shareholders and eliminated the NCI balance. Suncor recognized the difference between the fair value of the common shares issued and the NCI recorded at February 5, 2016 directly in equity. During the period from February 5, 2016 to March 21, 2016, when Suncor did not own 100% of the equity, net earnings of $11 million were earned that were attributable to the NCI owners.

As part of the acquisition, the company also assumed various pipeline and storage commitments of $3.0 billion undiscounted. The contract terms of these commitments range between one and 24 years, with payments that commenced in the first quarter of 2016.

Acquisition costs of $29 million have been charged to Operating, Selling and General expense in the consolidated statements of comprehensive income (loss) for the year ended December 31, 2016.

The acquisition of COS contributed $1.9 billion to gross revenues and a loss of $69 million to consolidated net income from the acquisition date to December 31, 2016.

Had the acquisition occurred on January 1, 2016, COS would have contributed $2.1 billion to gross revenues and a loss of $105 million to consolidated net income, which would have resulted in gross revenues of $27 billion and a consolidated net income of $408 million for the year ended December 31, 2016.

8. ACQUISITION OF ADDITIONAL OWNERSHIP INTEREST IN SYNCRUDE

On June 23, 2016, Suncor completed the purchase of an additional 5% working interest in the Syncrude joint operation from Murphy Oil Corporation's Canadian subsidiary for $946 million after purchase price adjustments. The purchase increased Suncor's share in the Syncrude joint operation to 53.74%.

The acquisition has been accounted for as a business combination using the acquisition method. The purchase price allocation is based on management's best estimates of fair values of Syncrude's assets and liabilities as at June 23, 2016.

($ millions)

Accounts receivable	8
Inventory	19
Property, plant and equipment	1 330
Exploration and evaluation	82
Total assets acquired	**1 439**
Accounts payable and other liabilities	(29)
Employee future benefits	(49)
Decommissioning provision	(187)
Deferred income taxes	(228)
Total liabilities assumed	**(493)**
Net assets acquired	**946**

The fair values of accounts receivable and accounts payable approximate their carrying values due to the short-term maturity of the instruments. The fair value of crude inventory was determined using quoted prices and rates from available pricing sources. The fair value of materials and supplies inventory approximates book value due to short-term turnover rates. The fair values of property, plant and equipment, and the decommissioning provision were determined using an expected future cash flow approach. Key assumptions used in the calculations were discount rates, future commodity prices and costs, timing of development activities, projections of oil reserves, and cost estimates to abandon and reclaim the mine and facilities. All of the key assumptions were applied on a consistent basis as the COS acquisition (note 7).

The additional interest in Syncrude contributed $191 million to gross revenues and $7 million to consolidated net income from the acquisition date to December 31, 2016.

Had the acquisition occurred on January 1, 2016, the additional interest would have contributed $275 million to gross revenues and a loss of $26 million to consolidated net income, which would have resulted in gross revenues of $27 billion and consolidated net income of $412 million for the year ended December 31, 2016.

9. OTHER INCOME

Other income consists of the following:

($ millions)	2016	2015
Energy trading activities		
Unrealized (losses) gains recognized in earnings during the period	**(47)**	28
Gains on inventory valuation	**62**	43
Risk management activities[1]	**(25)**	93
Risk mitigation and insurance proceeds[2]	**41**	121
Investment and interest income	**77**	62
Renewable energy grants	**24**	30
Change in value of pipeline commitments and other	**29**	95
	161	472

(1) Includes fair value changes related to short-term derivative contracts in the Oil Sands and Refining and Marketing segments and long-term forward-starting interest rate swaps in the Corporate segment.

(2) Includes property damage insurance proceeds recorded in the fourth quarter of 2016 for Syncrude in the Oil Sands segment, and property damage insurance proceeds recorded in the second quarter of 2016 and business interruption insurance proceeds recorded in the first quarter of 2015 for the Terra Nova asset in the Exploration and Production segment.

10. OPERATING, SELLING AND GENERAL

Operating, Selling and General expense consists of the following:

($ millions)	2016	2015
Contract services[1]	**3 363**	3 162
Employee costs[1]	**3 412**	2 920
Materials	**705**	1 140
Energy	**994**	756
Equipment rentals and leases	**267**	289
Travel, marketing and other	**409**	340
	9 150	8 607

(1) The company incurred $7.2 billion of contract services and employee costs for the year ended December 31, 2016 (2015 – $6.5 billion), of which $6.8 billion (2015 – $6.1 billion) was recorded in Operating, Selling and General expense and $0.4 billion was recorded as Property, Plant and Equipment (2015 – $0.4 billion). Employee costs include salaries, benefits and share-based compensation.

11. ASSET IMPAIRMENT AND DERECOGNITION

During the fourth quarter of 2016, the company recorded after-tax derecognition charges of $40 million on certain upgrading and logistics assets in the Oil Sands segment, as a result of the uncertainty of future benefits from these assets. As well, the company also recorded after-tax derecognition charges of $31 million in the Corporate segment relating to an initial investment in an undeveloped pipeline and on certain renewable energy assets, as a result of the uncertainty of future benefits from these assets.

During the second quarter of 2016, the company recognized an impairment charge of $33 million (net of taxes of $119 million) against certain Exploration and Evaluation assets in Norway as a result of future development uncertainty.

The impairments noted below were recognized during the year ended December 31, 2015.

Oil Sands

As a result of the decline in the crude oil price environment for the year ended December 31, 2015, the company performed impairment tests on its CGUs in the Oil Sands segment as at December 31, 2015. The tests were performed using a fair value less cost of disposal methodology. An expected cash flow approach was used based on 2015 year-end reserves data with the assumptions disclosed for the Oil Sands CGUs in note 21.

Joslyn Mining Project

As a result of the decline in crude oil prices and uncertainty in the timing of development plans, the company recognized an impairment charge of $290 million (net of taxes of $106 million) during the fourth quarter of 2015 related to its Exploration and Evaluation assets. The remaining carrying value of the company's share of the Joslyn mining project at December 31, 2015 was $nil.

Other

During the fourth quarter of 2015, the company recorded an impairment charge of $96 million (net of taxes of $34 million) in the Oil Sands segment following a review of certain assets, including engineering costs related to In Situ expansion, that no longer fit with Suncor's growth strategies and are not expected to be repurposed or otherwise deployed.

Exploration and Production

Libya

During the fourth quarter of 2015, as a result of shut-in production due to the continued closure of certain Libyan export terminals, escalating political unrest, asset damages confirmed during the fourth quarter, and the increasing uncertainty with respect to the company's return to normal operations in the country, the company recognized an impairment charge of $415 million (net of taxes of $nil) related to the remaining net assets of its Libyan Property, Plant and Equipment ($306 million), Exploration and Evaluation assets ($76 million) and inventory ($33 million).

Other

As a result of the decline in the crude oil price environment for the year ended December 31, 2015, the company performed impairment tests on its CGUs in the Exploration and Production segment as at December 31, 2015. The tests were performed using a fair value less cost of disposal methodology. An expected cash flow approach was used based on 2015 year-end reserves data with the following assumptions (Level 3 fair value inputs – see note 28):

- Brent price forecasts of US$46.60/bbl in 2016, US$56.20/bbl in 2017, and US$63.80/bbl in 2018 (all expressed in today's dollars), escalating at 2% per year thereafter and adjusted for asset-specific location and quality differentials; and
- Risk-adjusted discount rate of 9.0% on after-tax cash flows.

As a result of the impairment tests carried out as at December 31, 2015, the company recorded impairment charges of $359 million (net of taxes of $128 million) on its share of the White Rose assets, $331 million (net of taxes of $335 million) on its share of the Golden Eagle assets, and $54 million (net of taxes of $19 million) on its share of the Terra Nova assets. At December 31, 2015, the remaining carrying values of the White Rose, Golden Eagle, and Terra Nova assets were $520 million, $1.0 billion, and $910 million, respectively.

Estimates of the recoverable amounts of these assets are sensitive to discount rate and prices. A 1% increase in the discount rate would have resulted in an increase to after-tax impairment charges of $20 million related to the company's share of the White Rose assets, $15 million related to the company's share of the Golden Eagle assets, and $35 million related to the company's share of the Terra Nova assets. A 5% decrease in price would have resulted in an increase to after-tax impairment charges of $65 million on the company's share of the White Rose assets, $45 million related to the company's share of the Golden Eagle assets, and $85 million on the company's share of the Terra Nova assets.

During the fourth quarter of 2015, the company recognized an impairment charge to its exploration and evaluation assets of $54 million (net of taxes of $19 million) related to the Ballicatters East Coast Canada well as a result of future development uncertainty.

12. FINANCING EXPENSES

($ millions)	2016	2015
Interest on debt and finance leases	**1 012**	870
Capitalized interest at 5.7% (2015 – 5.8%)	**(597)**	(447)
Interest expense	**415**	423
Interest on pension and other post-retirement benefits	**59**	52
Accretion	**269**	197
Foreign exchange (gain) loss on U.S. dollar denominated debt	**(458)**	1 967
Foreign exchange and other	**61**	(82)
Loss on extinguishment of long-term debt	**99**	—
	445	2 557

During the second quarter of 2016, the company purchased US$688 million ($891 million) principal value (book value of $864 million) of subsidiary debt acquired through the acquisition of COS (note 7) for US$751 million ($973 million) including US$8 million ($10 million) of accrued interest, resulting in a debt extinguishment loss of $99 million. The company also repaid approximately $600 million of the credit facility acquired in the COS transaction.

During the third quarter of 2016, the company issued $700 million of senior unsecured Series 5 Medium Term Notes maturing on September 14, 2026. The notes have a coupon of 3.00% and were priced at $99.751 per Note for an effective yield of 3.029%. The company also issued $300 million of senior unsecured Series 5 Medium Term Notes maturing on September 13, 2046. The Notes have a coupon of 4.34% and were priced at $99.900 per Note for an effective yield of 4.346%.

13. INCOME TAXES

Income Tax (Recovery) Expense

($ millions)	2016	2015
Current:		
Current year	**222**	913
Adjustments to current income tax of prior years	**(69)**	(21)
Deferred:		
Origination of temporary differences	**(313)**	(998)
Adjustments in respect of deferred income tax of prior years	**67**	57
Changes in tax rates and legislation	**(190)**	17
Recognition of previously unrecognized deferred tax assets	**(76)**	—
	(359)	(32)

Reconciliation of Effective Tax Rate

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

($ millions)	**2016**	2015
Earnings (loss) before income tax	**86**	(2 027)
Canadian statutory tax rate	**27.00%**	26.34%
Statutory tax	**23**	(534)
Add (deduct) the tax effect of:		
Non-taxable component of capital (gains) losses	**(60)**	236
Share-based compensation and other permanent items	**19**	(3)
Assessments and adjustments	**(2)**	36
Impact of income tax rate and legislative changes	**(190)**	17
Foreign tax rate differential	**(28)**	(142)
Non-taxable impairment charge	**—**	109
Tax (gains) losses for which no deferred income tax asset was recognized	**(50)**	240
Recognition of deferred income tax asset previously unrecognized	**(76)**	—
Other	**5**	9
	(359)	(32)

Deferred Income Tax Balances

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

	Net Earnings (Loss)		Consolidated Balance Sheets [1]	
($ millions)	**2016**	2015	**Dec 31 2016**	Dec 31 2015
Property, plant and equipment	**(864)**	(466)	**13 864**	11 983
Decommissioning and restoration provision	**342**	(66)	**(1 701)**	(1 373)
Employee retirement benefit plans	**(23)**	(35)	**(648)**	(523)
Tax loss carry-forwards	**(10)**	(58)	**(109)**	(99)
Partnership deferral reserve	**(78)**	(56)	**—**	78
Foreign exchange and other	**121**	(243)	**(226)**	(147)
	(512)	(924)	**11 180**	9 919

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

($ millions)	**Dec 31 2016**	Dec 31 2015
Deferred income tax liability expected to reverse within 12 months	**195**	395
Deferred income tax asset expected to reverse within 12 months	**(21)**	(18)
Deferred income tax liability expected to reverse after 12 months	**11 048**	9 559
Deferred income tax asset expected to reverse after 12 months	**(42)**	(17)
Net deferred income tax liability	**11 180**	9 919

Change in Deferred Income Tax Balances

($ millions)	2016	2015
Beginning of year	**9 919**	10 517
Recognized in deferred income tax expense	**(512)**	(924)
Recognized in other comprehensive income	**(5)**	75
Recognized in equity	**(26)**	—
Acquisition	**2 054**	—
Foreign exchange, disposition and other	**(179)**	251
Reclassified to assets held for sale (note 39)	**(71)**	—
End of year	**11 180**	9 919

Deferred Tax in Shareholders' Equity

	Year ended December 31	
($ millions)	2016	2015
Deferred Tax in Comprehensive Income (Loss)		
Realized gain on assets available for sale	**—**	13
Actuarial gain (loss) on employment retirement benefit plans	**5**	(75)
Deferred Tax in Equity		
Common share issuance	**26**	—
	31	(62)

Deferred income tax assets are recognized for tax loss carry-forwards to the extent that the realization of the related tax benefit through future tax profits is probable. Suncor has not recognized a $125 million (2015 – $240 million) deferred tax asset on $926 million (2015 – $1.8 billion) of capital losses on foreign exchange on U.S. dollar denominated debt which can only be utilized against future capital gains.

No deferred tax liability has been recognized at December 31, 2016, on temporary differences of approximately $9.9 billion (2015 – $11.1 billion) associated with earnings retained in our investments in foreign subsidiaries, as the company is able to control the timing of the reversal of these differences. Based on current plans, repatriation of funds in excess of foreign reinvestment will not result in material additional income tax expense. Deferred distribution taxes associated with international business operations have not been recorded.

In the fourth quarter of 2016, the Government of Quebec enacted a decrease in the corporate income tax rate from 11.9% to 11.5% over four years effective January 1, 2017. As a result, the company revalued its deferred income tax balances, resulting in a deferred income tax recovery of $10 million.

In the third quarter of 2016, 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 50% to 40%. The company revalued its deferred income tax balances, resulting in a deferred income tax recovery of $180 million.

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. As a result, the company revalued its deferred income tax balances, resulting in a deferred income tax expense of $423 million.

In the first quarter of 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%. The company revalued its deferred income tax balances, resulting in a deferred income tax recovery of $406 million.

Canada Revenue Agency Update

In the fourth quarter of 2016, the Tax Court of Canada issued a favourable Order resolving the previously disclosed $1.3 billion tax dispute with the Canada Revenue Agency (CRA). The dispute was regarding the income tax treatment of

realized losses in 2007 on the settlement of certain derivative contracts. The Tax Court of Canada Order has confirmed the successful resolution of the matter between Suncor and the CRA, resulting in no additional taxes, interest or penalties. All of the security which Suncor had posted with respect to this item has now been returned to the company.

14. EARNINGS (LOSS) PER COMMON SHARE

($ millions)	2016	2015
Net earnings (loss)	**445**	(1 995)
Dilutive impact of accounting for awards as equity-settled [1]	**(1)**	—
Net earnings (loss) – diluted	**444**	(1 995)
Net earnings (loss) attributable to common shareholders	**434**	(1 995)
Dilutive impact of accounting for awards as equity-settled [1]	**(1)**	—
Net earnings (loss) – diluted attributable to common shareholders	**433**	(1 995)

(millions of common shares)		
Weighted average number of common shares	**1 610**	1 446
Dilutive securities:		
Effect of share options	**2**	1
Weighted average number of diluted common shares	**1 612**	1 447

(dollars per common share)		
Basic and diluted earnings (loss) per share	**0.28**	(1.38)
Basic and diluted earnings (loss) per share attributable to common shareholders	**0.27**	(1.38)

(1) Cash payment alternatives are accounted for as cash-settled plans. As these awards can be exchanged for common shares of the company, they are considered potentially dilutive and are included in the calculation of the company's diluted net earnings (loss) per share if they have a dilutive impact in the period. Accounting for these awards as equity-settled was determined to have a dilutive impact for the year ended December 31, 2016.

15. CASH AND CASH EQUIVALENTS

($ millions)	Dec 31 2016	Dec 31 2015
Cash	**1 103**	846
Cash equivalents	**1 913**	3 203
	3 016	4 049

16. SUPPLEMENTAL CASH FLOW INFORMATION

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

($ millions)	2016	2015
Accounts receivable	**(471)**	1 377
Inventories	**(218)**	458
Accounts payable and accrued liabilities	**110**	(327)
Current portion of provisions	**(98)**	(18)
Income taxes payable (net)	**145**	(1 415)
	(532)	75
Relating to:		
Operating activities	**(308)**	78
Investing activities	**(224)**	(3)
	(532)	75

17. INVENTORIES

($ millions)	Dec 31 2016	Dec 31 2015
Crude oil	**1 110**	1 073
Refined products	**1 193**	1 184
Materials, supplies and merchandise	**680**	581
Energy trading commodity inventories	**515**	252
Reclassified to assets held for sale (note 39)	**(258)**	—
	3 240	3 090

During 2016, product inventories of $10.1 billion (2015 – $11.9 billion) were recorded as an expense. There was a write-down of crude oil of $32 million (2015 – $40 million), a write-down of refined products of $nil (2015 – $19 million), and a write-down of materials, supplies and merchandise of $26 million in 2016 (2015 – $18 million). Energy trading commodity inventories are measured at fair value less costs of disposal based on Level 1 and Level 2 fair value inputs.

18. PROPERTY, PLANT AND EQUIPMENT

($ millions)	Oil and Gas Properties	Plant and Equipment	Total
Cost			
At December 31, 2014	29 235	55 587	84 822
Additions	1 783	4 646	6 429
Acquisitions (note 36)	—	888	888
Changes in decommissioning and restoration	381	15	396
Disposals and derecognition	(3)	(618)	(621)
Foreign exchange adjustments	1 239	559	1 798
At December 31, 2015	32 635	61 077	93 712
Additions	**1 428**	**5 142**	**6 570**
Transfers from exploration and evaluation	**65**	**—**	**65**
Acquisitions (notes 7, 8)	**1 678**	**9 128**	**10 806**
Changes in decommissioning and restoration	**(68)**	**21**	**(47)**
Disposals and derecognition	**(166)**	**(803)**	**(969)**
Foreign exchange adjustments	**(1 431)**	**(121)**	**(1 552)**
Reclassified to assets held for sale (note 39)	**—**	**(907)**	**(907)**
At December 31, 2016	**34 141**	**73 537**	**107 678**
Accumulated provision			
At December 31, 2014	(9 937)	(15 085)	(25 022)
Depreciation and depletion	(2 280)	(2 779)	(5 059)
Impairment (note 11)	(1 596)	(131)	(1 727)
Disposals and derecognition	—	200	200
Foreign exchange adjustments	(629)	(324)	(953)
At December 31, 2015	(14 442)	(18 119)	(32 561)
Depreciation and depletion	**(2 598)**	**(3 133)**	**(5 731)**
Disposals and derecognition	**—**	**645**	**645**
Foreign exchange adjustments	**978**	**55**	**1 033**
Reclassified to assets held for sale (note 39)	**—**	**195**	**195**
At December 31, 2016	**(16 062)**	**(20 357)**	**(36 419)**
Net property, plant and equipment			
December 31, 2015	18 193	42 958	61 151
December 31, 2016	**18 079**	**53 180**	**71 259**

($ millions)	Dec 31, 2016 Cost	Accumulated Provision	Net Book Value	Dec 31, 2015 Cost	Accumulated Provision	Net Book Value
Oil Sands	**73 882**	**(19 341)**	**54 541**	58 958	(15 991)	42 967
Exploration and Production	**20 058**	**(12 020)**	**8 038**	20 469	(11 810)	8 659
Refining and Marketing	**12 741**	**(4 363)**	**8 378**	12 657	(3 965)	8 692
Corporate, Energy Trading and Eliminations	**997**	**(695)**	**302**	1 628	(795)	833
	107 678	**(36 419)**	**71 259**	93 712	(32 561)	61 151

At December 31, 2016, the balance of assets under construction and not subject to depreciation or depletion was $16.0 billion (December 31, 2015 – $12.8 billion).

At December 31, 2016, Property, Plant and Equipment included finance leases with a net book value of $1.2 billion (December 31, 2015 – $1.2 billion).

19. EXPLORATION AND EVALUATION ASSETS

($ millions)	2016	2015
Beginning of year	**1 681**	2 248
Acquisitions and additions (Note 7, 8 and 35)	**787**	240
Transfers to oil and gas assets	**(65)**	—
Dry hole expenses	**(204)**	(255)
Impairment (note 11)	**(152)**	(556)
Amortization	**(1)**	(7)
Foreign exchange adjustments	**(8)**	11
End of year	**2 038**	1 681

20. OTHER ASSETS

($ millions)	Dec 31 2016	Dec 31 2015
Investments (note 38)	**191**	211
Prepaids and other	**1 057**	942
	1 248	1 153

Prepaids and other includes long-term accounts receivables related to deposits paid on Notices of Reassessments that have been received from the CRA and are unlikely to be settled within one year.

21. GOODWILL AND OTHER INTANGIBLE ASSETS

	Oil Sands	Refining and Marketing			
($ millions)	Goodwill	Goodwill	Brand name	Customer lists	Total
At December 31, 2014	2 752	148	166	17	3 083
Amortization	—	—	—	(4)	(4)
At December 31, 2015	2 752	148	166	13	3 079
Amortization	**—**	**—**	**—**	**(4)**	**(4)**
At December 31, 2016	**2 752**	**148**	**166**	**9**	**3 075**

The company performed a goodwill impairment test at December 31, 2016 on its Oil Sands CGUs. Recoverable amounts were based on fair value less costs of disposal calculated using the present value of the CGUs' expected future cash flows. The primary sources of cash flow information are derived from business plans approved by executives of the company, which were developed based on macroeconomic factors such as forward price curves for benchmark commodities, inflation rates and industry supply-demand fundamentals. When required, the projected cash flows in the business plans have been updated to reflect current market assessments of key assumptions, including long-term forecasts of commodity prices, inflation rates, foreign exchange rates and discount rates specific to the asset (Level 3 fair value inputs).

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

Future cash flow estimates are discounted using after-tax risk-adjusted discount rates. The discount rates are calculated based on the weighted average cost of capital of a group of relevant peers that is considered to represent the rate of return that would be required by a typical market participant for similar assets. The after-tax discount rate applied to cash flow projections was 8% (2015 – 8%). The company based its cash flow projections on an average West Texas Intermediate (WTI) price of US$55.00 per barrel in 2017, US$60.90 per barrel in 2018, US$66.47 per barrel in 2019, and then escalating at an average of 4% per year from 2020 – 2022 and at an average of 2% thereafter, adjusted for applicable quality and location differentials depending on the underlying CGU. The forecast cash flow period ranged from 20 years to 50 years based on the reserves life of the respective CGU. As a result of this analysis, management did not identify impairment within any of the CGUs comprising the Oil Sands operating segment and the associated allocated goodwill.

The company also performed a goodwill impairment test of its Refining and Marketing CGUs. The recoverable amounts are based on the fair value less costs of disposal calculated using the present value of the CGUs' expected future cash flows, based primarily on the business plan and historical results adjusted for current economic conditions, and escalated using an inflation rate of 2% of revenue and operating costs. The after-tax discount rates applied to the cash flow projection were between 10% and 15% (2015 – between 10% and 15%). As a result of this analysis, no impairment was identified within the operating segment or the associated allocated goodwill.

22. DEBT AND CREDIT FACILITIES

Debt and credit facilities are comprised of the following:

Short-Term Debt

($ millions)	**Dec 31 2016**	Dec 31 2015
Commercial paper[1]	**1 273**	747

(1) The commercial paper is supported by a revolving credit facility with a syndicate of lenders. The company is authorized to issue commercial paper to a maximum of $4.0 billion having a term not to exceed 365 days. The weighted average interest rate as at December 31, 2016 was 0.97% (December 31, 2015 – 0.5%).

Long-Term Debt

($ millions)	Dec 31 2016	Dec 31 2015
Fixed-term debt, redeemable at the option of the company [2]		
6.85% Notes, due 2039 (US$750)	**1 004**	1 038
6.80% Notes, due 2038 (US$900)	**1 231**	1 277
6.50% Notes, due 2038 (US$1150)	**1 540**	1 592
5.95% Notes, due 2035 (US$600)	**769**	780
5.95% Notes, due 2034 (US$500)	**669**	692
5.35% Notes, due 2033 (US$300)	**368**	368
7.15% Notes, due 2032 (US$500)	**670**	692
3.60% Notes, due 2024 (US$750)	**1 002**	1 038
3.10% Series 5 Medium Term Notes, due 2021	**748**	750
6.10% Notes, due 2018 (US$1250)	**1 678**	1 730
6.05% Notes, due 2018 (US$600)	**809**	836
7.00% Debentures, due 2028 (US$250)	**342**	355
7.875% Debentures, due 2026 (US$275)	**391**	412
9.25% Debentures, due 2021 (US$300)	**440**	472
5.39% Series 4 Medium Term Notes, due 2037	**599**	600
5.80% Series 4 Medium Term Notes, due 2018	**700**	700
3.00% Series 5 Medium Term Notes, due 2026 [3]	**698**	—
4.34% Series 5 Medium Term Notes, due 2046 [4]	**300**	—
4.50% Notes, due 2022 (US$182) [5]	**225**	—
6.00% Notes, due 2042 (US$152) [5]	**151**	—
9.40% Notes, due 2021 (US$220) [5][6]	**325**	—
7.75% Notes, due 2019 (US$223) [5]	**317**	—
8.20% Notes, due 2027 (US$59) [5]	**87**	—
Total unsecured long-term debt	**15 063**	13 332
Secured long-term debt	**—**	13
Finance leases [7]	**1 134**	1 268
Deferred financing costs	**(40)**	(57)
	16 157	14 556
Current portion of long-term debt		
Finance leases	**(54)**	(57)
Secured long-term debt	**—**	(13)
	(54)	(70)

Total long-term debt	**16 103**	14 486

(2) The value of debt includes the unamortized balance of premiums or discounts.

(3) In September 2016, the company issued $700 million of senior unsecured series 5 medium term notes maturing on September 14, 2026. The notes have a coupon of 3.00% and were priced at $99.751 per note for an effective yield of 3.029%. Interest is paid semi-annually.

(4) In September 2016, the company issued $300 million of senior unsecured series 5 medium term notes maturing on September 13, 2046. The notes have a coupon of 4.34% and were priced at $99.900 per note for an effective yield of 4.346%. Interest is paid semi-annually.

(5) Debt acquired through the acquisition of COS (note 7).

(6) Subsequent to the acquisition of COS, Moody's Investors Services downgraded COS long-term senior debt rating from Baa3 (negative outlook) to Ba3 (stable outlook). This triggered a change in the coupon rate of the note from 7.9% to 9.40%.

(7) Interest rates range from 4.6% to 16.5% and maturity dates range from 2017 to 2052.

Scheduled Debt Repayments

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

($ millions)	Repayment
2017	1 328
2018	3 240
2019	322
2020	25
2021	1 476
Thereafter	11 099
	17 490

Credit Facilities

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

($ millions)	**2016**
Fully revolving and expires in 2019	**7 685**
Fully revolving and expires in 2018	**1 750**
Fully revolving and expires in 2017 (2)	**950**
Can be terminated at any time at the option of the lenders	**164**
Total credit facilities	**10 549**
Credit facilities supporting outstanding commercial paper	**(1 273)**
Credit facilities supporting standby letters of credit (1)	**(1 139)**
Total unutilized credit facilities (2)	**8 137**

(1) To reduce costs, the company supported certain credit facilities with $1 032 million of cash collateral as at December 31, 2016 (December 31, 2015 – $1 348 million).

(2) Available credit facilities for general purposes were $7 467 million at December 31, 2016 (December 31, 2015 – $7 034 million). Subsequent to year end, the company cancelled a $950 million credit facility that was acquired through the acquisition of COS (note 7), reducing available lines of credit to $6.5 billion.

23. OTHER LONG-TERM LIABILITIES

($ millions)	**Dec 31 2016**	Dec 31 2015
Pensions and other post-retirement benefits (note 24)	**1 464**	1 026
Share-based compensation plans (note 27)	**364**	309
Deferred revenue	**55**	60
Libya Exploration and Production Sharing Agreement (EPSA) signature bonus (1)	**83**	87
Other	**131**	91
Reclassified to assets held for sale (note 39)	**(30)**	—
	2 067	1 573

(1) As part of the 2009 acquisition of Petro-Canada, the company assumed the remaining US$500 million obligation for a signature bonus relating to Petro-Canada's ratification of six EPSAs in Libya. At December 31, 2016, the carrying amount of the Libya EPSAs signature bonus was $85 million (December 31, 2015 – $90 million). The current portion is $2 million (December 31, 2015 – $3 million) and is recorded in Accounts Payable and Accrued Liabilities.

24. PENSIONS AND OTHER POST-RETIREMENT BENEFITS

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

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

Funding of the registered retirement plans complies with applicable regulations that require actuarial valuations of the pension funds at least once every three years in Canada, or more, depending on funding status, and every year in the United States. The most recent valuations for the Canadian plans were performed as at December 31, 2013, and for the International plans were performed as at December 31, 2015. The company uses a measurement date of December 31 to value the plan assets and remeasure the accrued benefit obligation for accounting purposes.

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

The company reports its share of Syncrude's defined benefit and defined contribution pension plans and Syncrude's other post-retirement benefits plan.

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

Defined Benefit Obligations and Funded Status

($ millions)	Pension Benefits 2016	Pension Benefits 2015	Other Post-Retirement Benefits 2016	Other Post-Retirement Benefits 2015
Change in benefit obligation				
Benefit obligation at beginning of year	**4 611**	4 542	**502**	498
Obligations acquired through acquisition of COS (note 7)	**1 352**	—	**73**	—
Current service costs	**189**	167	**13**	11
Plan participants' contributions	**14**	14	**—**	—
Benefits paid	**(272)**	(214)	**(21)**	(19)
Interest costs	**238**	183	**23**	19
Foreign exchange	**(46)**	43	**(1)**	4
Settlements	**8**	2	**—**	—
Actuarial remeasurement:				
Experience loss (gain) arising on plan liabilities	**7**	(20)	**(5)**	(4)
Actuarial loss (gain) arising from changes in demographic assumptions	**8**	—	**(1)**	(5)
Actuarial loss (gain) arising from changes in financial assumptions	**171**	(106)	**4**	(2)
Benefit obligation at end of year	**6 280**	4 611	**587**	502
Change in plan assets				
Fair value of plan assets at beginning of year	**4 040**	3 755	**—**	—
Assets acquired through acquisition of COS (note 7)	**1 060**	—	**—**	—
Employer contributions	**165**	112	**—**	—
Plan participants' contributions	**14**	14	**—**	—
Benefits paid	**(249)**	(195)	**—**	—
Foreign exchange	**(37)**	54	**—**	—
Settlements	**8**	2	**—**	—
Administrative costs	**(2)**	(2)	**—**	—
Income on plan assets	**202**	150	**—**	—
Actuarial remeasurement:				
Return on plan assets greater than discount rate	**155**	150	**—**	—
Fair value of plan assets at end of year	**5 356**	4 040	**—**	—
Net unfunded obligation	**924**	571	**587**	502

Of the total net unfunded obligation as at December 31, 2016, 66% relates to Canadian pension and other post-retirement benefits obligation (excluding Syncrude) (December 31, 2015 – 85%). The weighted average duration of the defined benefit obligation under the Canadian pension and other post-retirement plans (excluding Syncrude) is 14.06 years (2015 – 14.9 years).

The net unfunded obligation is recorded in Accounts Payable and Accrued Liabilities of $47 million and Other Long-Term Liabilities (note 23) in the Consolidated Balance Sheets.

($ millions)	Pension Benefits 2016	Pension Benefits 2015	Other Post-Retirement Benefits 2016	Other Post-Retirement Benefits 2015
Analysis of amount charged to earnings:				
Current service costs	**189**	167	**13**	11
Interest costs	**36**	33	**23**	19
Defined benefit plans expense	**225**	200	**36**	30
Defined contribution plans expense	**76**	71	**—**	—
Total benefit plans expense charged to earnings	**301**	271	**36**	30

Components of defined benefit costs recognized in Other Comprehensive Income:

($ millions)	Pension Benefits 2016	Pension Benefits 2015	Other Post-Retirement Benefits 2016	Other Post-Retirement Benefits 2015
Return on plan assets (excluding amounts included in net interest expense)	**(155)**	(150)	**—**	—
Experience loss (gain) arising on plan liabilities	**7**	(20)	**(5)**	(4)
Actuarial loss (gain) arising from changes in financial assumptions	**8**	(106)	**(1)**	(2)
Actuarial loss (gain) arising from changes in demographic assumptions	**171**	—	**4**	(5)
Actuarial loss (gain) recognized in other comprehensive income	**31**	(276)	**(2)**	(11)

Actuarial Assumptions

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

The significant weighted average actuarial assumptions were as follows:

(%)	Pension Benefits Dec 31 2016	Pension Benefits Dec 31 2015	Other Post-Retirement Benefits Dec 31 2016	Other Post-Retirement Benefits Dec 31 2015
Discount rate	**3.90**	4.00	**3.80**	3.90
Rate of compensation increase	**3.20**	2.90	**3.00**	3.20

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

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

In order to measure the expected cost of other post-retirement benefits, it was assumed for 2016 that the health care costs would increase annually by 6.50% per person (2015 – 7%). This rate will remain constant in 2017 and will decrease 0.5% annually to 5% by 2022, and remain at that level thereafter.

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

($ millions)	Pension Benefits Increase	Pension Benefits Decrease
1% change in discount rate		
Effect on the aggregate service and interest costs	(21)	27
Effect on the benefit obligations	(808)	1 041

($ millions)	Other Post-Retirement Benefits Increase	Other Post-Retirement Benefits Decrease
1% change in discount rate		
Effect on the benefit obligations	(70)	87
1% change in health care cost		
Effect on the aggregate service and interest costs	1	(1)
Effect on the benefit obligations	33	(28)

Plan Assets and Investment Objectives

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

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

(%)	**2016**	2015
Equities, comprised of:		
– Canada	**19**	17
– United States	**23**	24
– Foreign	**17**	19
	59	60
Fixed income, comprised of:		
– Canada	**39**	40
Real estate, comprised of:		
– Canada	**2**	—
Total	**100**	100

Equity securities do not include any direct investments in Suncor shares. The fair value of equity and bond securities are based on the trading price of the underlying fund. The fair value of real estate investments is based on independent third-party appraisals.

During the year, the company made cash contributions of $165 million to its defined benefit pension plans, of which $3 million was contributed to the solvency reserve account in Alberta. The company expects to make cash contributions to its defined benefit pension plans in 2017 of $176 million.

25. PROVISIONS

($ millions)	Decommissioning and Restoration[1]	Royalties	Other[2]	Total
At December 31, 2014	5 101	272	274	5 647
Liabilities incurred	290	5	60	355
Change in discount rate	(347)	—	—	(347)
Changes in estimates	426	49	5	480
Liabilities settled	(302)	(3)	(63)	(368)
Accretion	199	—	2	201
Asset divestitures	11	—	—	11
Foreign exchange	127	—	2	129
At December 31, 2015	5 505	323	280	6 108
Less: current portion	(376)	(323)	(70)	(769)
	5 129	—	210	5 339
At December 31, 2015	5 505	323	280	6 108
Liabilities incurred	**279**	**93**	**53**	**425**
Change in discount rate	**532**	**—**	**—**	**532**
Changes in estimates	**(824)**	**(79)**	**11**	**(892)**
Liabilities settled	**(269)**	**(30)**	**(68)**	**(367)**
Accretion	**269**	**—**	**—**	**269**
Asset acquisitions (notes 7 and 8)	**1 356**	**—**	**—**	**1 356**
Foreign exchange	**(98)**	**—**	**(1)**	**(99)**
Reclassified to assets held for sale (note 39)	**(4)**	**—**	**(5)**	**(9)**
At December 31, 2016	**6 746**	**307**	**270**	**7 323**
Less: current portion	**(403)**	**(307)**	**(71)**	**(781)**
	6 343	**—**	**199**	**6 542**

(1) Represents decommissioning and restoration provisions associated with the retirement of Property, Plant and Equipment and Exploration and Evaluation assets. The total undiscounted amount of estimated future cash flows required to settle the obligations at December 31, 2016 was approximately $11.7 billion (December 31, 2015 – $9.9 billion). A weighted average credit-adjusted risk-free interest rate of 3.90% was used to discount the provision recognized at December 31, 2016 (December 31, 2015 – 4.37%). The credit-adjusted risk-free rate used reflects the expected time frame of the provisions. Payments to settle the decommissioning and restoration provisions occur on an ongoing basis and will continue over the lives of the operating assets, which can exceed 50 years.

(2) Includes legal, environmental and lease inducements provisions.

Sensitivities

Changes to the discount rate would have the following impact on Decommissioning and Restoration liabilities:

As at December 31	**2016**	2015
1% Increase	**(1 036)**	(648)
1% Decrease	**1 506**	864

26. SHARE CAPITAL

Authorized

Common Shares

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

Preferred Shares

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

Share Issuance

On June 22, 2016, the company issued 82.2 million common shares for $35.00 per common share. Gross proceeds were approximately $2.878 billion ($2.782 billion net of fees).

Normal Course Issuer Bid

Until August 4, 2016, the company was authorized to repurchase shares pursuant to a normal course issuer bid (NCIB) through the facilities of the Toronto Stock Exchange, New York Stock Exchange and/or alternative trading platforms. Under the NCIB, the company was authorized to purchase for cancellation up to approximately $500 million worth of its common shares beginning August 5, 2015 and ending August 4, 2016.

The following table summarizes the share repurchase activities during the period:

($ millions, except as noted)	2016	2015
Share repurchase activities (thousands of common shares)		
Shares repurchased	—	1 230
Amounts charged to		
Share capital	—	17
Retained earnings	—	26
Share repurchase cost	—	43
Average repurchase cost per share	—	34.93

In accordance with applicable securities law, repurchases under the program were suspended on October 5, 2015, as a result of the offer to the shareholders of COS. The company did not resume repurchases after the offer was completed and did not renew its NCIB in response to the lower crude price environment.

27. SHARE-BASED COMPENSATION

Share-Based Compensation Expense

Reflected in the Consolidated Statements of Comprehensive Income (Loss) within Operating, Selling and General expense are the following share-based compensation amounts:

($ millions)	2016	2015
Equity-settled plans	**48**	44
Cash-settled plans	**395**	254
Total share-based compensation expense	**443**	298

Liability Recognized for Share-Based Compensation

Reflected in the consolidated Balance Sheets within accounts payable and accrued liabilities and other long-term liabilities are the following fair value amounts for the company's cash-settled plans:

($ millions)	**2016**	2015
Current Liability	**359**	322
Long-Term Liability (note 23)	**364**	309
Total Liability	**723**	631

The intrinsic value of the vested awards at December 31, 2016 was $406 million (December 31, 2015 – $356 million).

Stock Option Plans

Suncor grants stock option awards as a form of retention and incentive compensation.

(a) Active Stock Option Plan

Stock options granted by the company on or after August 1, 2010 provide the holder with the right to purchase common shares at the grant date market price, subject to fulfilling vesting terms. This plan replaced the pre-merger stock option plan of legacy Suncor and legacy Petro-Canada. Options granted have a seven-year life, vest annually over a three-year period and are accounted for as equity-settled awards.

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

	2016	2015
Annual dividend per share	**$1.16**	$1.14
Risk-free interest rate	**0.55%**	0.65%
Expected life	**5 years**	5 years
Expected volatility	**28%**	28%
Weighted average fair value per option	**$4.60**	$6.68

The expected life is based on historical stock option exercise data and current expectations. The expected volatility considers the historical volatility in the price of Suncor's common shares over a period similar to the life of the options, and is indicative of future trends.

(b) Discontinued Stock Option Plans

Executive and Key Contributor Stock Options

Options granted under these plans generally have a seven-to-ten-year life and vest over a three-year period. These plans were in place prior to August 1, 2009, and are accounted for as equity-settled awards.

Suncor Energy Inc. Stock Options with TSARs

Options granted between August 1, 2009 and July 31, 2010, have a seven-year life and vest annually over a three-year period. Each option included a tandem stock appreciation right (TSAR), allowing the option holder the right to receive a cash payment equal to the excess of the market price of Suncor's common shares at the time of exercise over the exercise price of the option. These awards are accounted for as cash-settled.

Legacy Petro-Canada Stock Options with CPAs

Options granted to executives and key employees prior to August 1, 2009, and can be settled in common shares or exchanged for a cash payment alternative (CPA). Options granted have a seven-year life, vest over periods of up to four years and are accounted for as cash-settled awards. All options granted under this plan have expired at December 31, 2016.

The following table presents a summary of the activity related to Suncor's stock option plans:

	2016		2015	
	Number (thousands)	**Weighted Average Exercise Price ($)**	Number (thousands)	Weighted Average Exercise Price ($)
Outstanding, beginning of year	**29 090**	**36.97**	27 464	36.97
Granted	**8 145**	**30.26**	7 132	38.86
Exercised for cash payment	**(1 441)**	**30.39**	(28)	34.60
Exercised as options for common shares	**(3 983)**	**33.36**	(3 123)	30.21
Forfeited/expired	**(369)**	**38.12**	(2 355)	42.94
Outstanding, end of year	**31 442**	**35.98**	29 090	36.97
Exercisable, end of year	**17 821**	**37.74**	17 527	37.95

Options are exercised regularly throughout the year. Therefore, the weighted average share price during the year of $36.23 (2015 – $36.49) is representative of the weighted average share price at the date of exercise.

For the options outstanding at December 31, 2016, the exercise price ranges and weighted average remaining contractual lives are shown below:

	Outstanding	
Exercise Prices ($)	Number (thousands)	Weighted Average Remaining Contractual Life (years)
19.44-29.99	**330**	2
30.00-39.99	**25 393**	5
40.00-49.99	**5 584**	1
50.00-59.99	**41**	1
60.00-69.97	**94**	1
Total	**31 442**	4

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

(thousands)	**2016**	2015
	10 937	18 626

Share Unit Plans

Suncor grants share units as a form of retention and incentive compensation. Share unit plans are accounted for as cash-settled awards.

(a) Performance Share Units (PSUs)

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

(b) Restricted Share Units (RSUs)

A RSU is a time-vested award entitling employees to receive cash calculated based on an average of the company's share price leading up to vesting. RSUs vest approximately three years after the grant date.

(c) Deferred Share Units (DSUs)

A DSU is redeemable for cash or a common share for a period of time after a unitholder ceases employment or Board membership. The DSU Plan is limited to executives and members of the Board of Directors. Members of the Board of Directors receive an annual grant of DSUs as part of their compensation and may elect to receive their fees in cash only or in increments of 50% or 100% allocated to DSUs. Executives may elect to receive their annual incentive bonus in cash only or in increments of 25%, 50%, 75% or 100% allocated to DSUs.

The following table presents a summary of the activity related to Suncor's share unit plans:

(thousands)	PSU	RSU	DSU
Outstanding, December 31, 2014	2 596	19 600	1 045
Granted	1 185	6 743	181
Redeemed for cash	(1 316)	(6 240)	(154)
Forfeited/expired	—	(999)	—
Outstanding, December 31, 2015	2 465	19 104	1 072
Granted	**1 683**	**6 194**	**186**
Redeemed for cash	**(1 714)**	**(6 649)**	**(40)**
Forfeited/expired	**(21)**	**(491)**	**—**
Outstanding, December 31, 2016	**2 413**	**18 158**	**1 218**

Stock Appreciation Rights (SARs)

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

(a) Suncor Energy Inc. SARs

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

(b) Legacy Petro-Canada SARs

This plan was discontinued on August 1, 2009. These SARs have a seven-year life and vest annually over a four-year period. All SARs granted under this plan have expired at December 31, 2016.

The following table presents a summary of the activity related to Suncor's SAR plans:

	2016		2015	
	Number (thousands)	**Weighted Average Exercise Price ($)**	Number (thousands)	Weighted Average Exercise Price ($)
Outstanding, beginning of year	**957**	**27.98**	2 563	27.05
Granted	**142**	**30.23**	121	38.90
Exercised	**(610)**	**23.07**	(1 690)	27.22
Forfeited/expired	**(4)**	**19.44**	(37)	33.72
Outstanding, end of year	**485**	**34.90**	957	27.98
Exercisable, end of year	**240**	**36.29**	759	25.52

28. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

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

Non-Derivative Financial Instruments

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

The company's long-term debt and long-term financial liabilities are recorded at amortized cost using the effective interest method. At December 31, 2016, the carrying value of fixed-term debt accounted for under amortized cost was $15.1 billion (December 31, 2015 – $13.3 billion) and the fair value at December 31, 2016 was $17.5 billion (December 31, 2015 – $14.5 billion). The estimated fair value of long-term debt is based on pricing sourced from market data, which is considered a Level 2 fair value input.

Derivative Financial Instruments

(a) Non-Designated Derivative Financial Instruments

- Energy Trading Derivatives – The company's Energy Trading group uses physical and financial energy derivative contracts, including swaps, forwards and options to earn trading revenues.
- Risk Management Derivatives – The company periodically enters into derivative contracts in order to manage exposure to interest rates, commodity price and foreign exchange movements and which are a component of the company's overall risk management program.

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

($ millions)	Energy Trading	Risk Management	Total
Fair value of contracts outstanding at December 31, 2014	20	110	130
Cash Settlements – received during the year	(66)	(183)	(249)
Unrealized gains recognized in earnings during the year (note 9)	28	93	121
Fair value outstanding at December 31, 2015	(18)	20	2
Cash Settlements – paid (received) during the year	**29**	**(13)**	**16**
Unrealized losses recognized in earnings during the year (note 9)	**(47)**	**(25)**	**(72)**
Fair value outstanding at December 31, 2016	**(36)**	**(18)**	**(54)**

(b) Fair Value Hierarchy

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

- Level 1 consists of instruments with a fair value determined by an unadjusted quoted price in an active market for identical assets or liabilities. An active market is characterized by readily and regularly available quoted prices where the prices are representative of actual and regularly occurring market transactions to assure liquidity.
- Level 2 consists of instruments with a fair value that is determined by quoted prices in an inactive market, prices with observable inputs, or prices with insignificant non-observable inputs. The fair value of these positions is determined using observable inputs from exchanges, pricing services, third-party independent broker quotes, and published transportation tolls. The observable inputs may be adjusted using certain methods, which include extrapolation over the quoted price term and quotes for comparable assets and liabilities.

- Level 3 consists of instruments with a fair value that is determined by prices with significant unobservable inputs. As at December 31, 2016, the company does not have any derivative instruments measured at fair value Level 3.

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

The following table presents the company's derivative financial instrument assets and liabilities and assets available for sale measured at fair value for each hierarchy level as at December 31, 2016 and 2015.

($ millions)	Level 1	Level 2	Level 3	Total Fair Value
Accounts receivable	14	76	—	90
Accounts payable	(20)	(68)	—	(88)
Balance at December 31, 2015	(6)	8	—	2
Accounts receivable	**46**	**109**	**—**	**155**
Accounts payable	**(100)**	**(109)**	**—**	**(209)**
Balance at December 31, 2016	**(54)**	**—**	**—**	**(54)**

During the year ended December 31, 2016, there were no transfers between Level 1 and Level 2 fair value measurements.

Offsetting Financial Assets and Liabilities

The company enters into arrangements that allow for offsetting of derivative financial instruments and accounts receivable (payable), which are presented on a net basis on the balance sheet, as shown in the table below as at December 31, 2016 and 2015.

Financial Assets

($ millions)	Gross Assets	Gross Liabilities Offset	Net Amounts Presented
Derivatives	1 631	(1 541)	90
Accounts receivable	1 799	(960)	839
Balance at December 31, 2015	3 430	(2 501)	929
Derivatives	**1 765**	**(1 610)**	**155**
Accounts receivable	**2 058**	**(946)**	**1 112**
Balance at December 31, 2016	**3 823**	**(2 556)**	**1 267**

Financial Liabilities

($ millions)	Gross Liabilities	Gross Assets Offset	Net Amounts Presented
Derivatives	(1 629)	1 541	(88)
Accounts payable	(1 865)	960	(905)
Balance at December 31, 2015	(3 494)	2 501	(993)
Derivatives	**(1 819)**	**1 610**	**(209)**
Accounts payable	**(1 975)**	**946**	**(1 029)**
Balance at December 31, 2016	**(3 794)**	**2 556**	**(1 238)**

Risk Management

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

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

The nature of the risks faced by the company and its policies for managing such risks remains unchanged from December 31, 2015.

1) Market Risk

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

(a) Commodity Price Risk

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

An increase of US$10.00 per barrel of crude oil as at December 31, 2016 would decrease pre-tax earnings for the company's outstanding derivative financial instruments by approximately $112 million (2015 – $79 million).

(b) Foreign Currency Exchange Risk

The company is exposed to foreign currency exchange risk on revenues, capital expenditures, or financial instruments that are denominated in a currency other than the company's functional currency (Canadian dollars). As crude oil is priced in U.S. dollars, fluctuations in US$/Cdn$ exchange rates may have a significant impact on revenues. This exposure is partially offset through the issuance of U.S. dollar denominated debt. A 1% strengthening in the Cdn$ relative to the US$ as at December 31, 2016 would increase earnings related to the company's debt by approximately $129 million (2015 – $120 million).

(c) Interest Rate Risk

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

To manage the company's exposure to interest rate volatility, the company may periodically enter into interest rate swap contracts to fix the interest rate of future debt issuances. As at December 31, 2016, the company had executed $1.9 billion in forward starting swaps. To the extent fixed interest rates increased by 1%, it is estimated that the company's pre-tax earnings would increase by $264 million (2015 – $204 million). The weighted average interest rate on total debt for the year ended December 31, 2016 was 6.2% (2015 – 6.1%).

The company's net earnings are sensitive to changes in interest rates on the floating rate portion of the company's debt, which are offset by cash balances. To the extent interest expense is not capitalized, if interest rates applicable to floating rate instruments increased by 1%, it is estimated that the company's pre-tax earnings would increase by approximately $17 million (2015 – $33 million). This assumes that the amount and mix of fixed and floating rate debt remains unchanged from December 31, 2016. The proportion of floating interest rate exposure at December 31, 2016 was 7.8% of total debt outstanding (2015 – 5.3%).

2) Liquidity Risk

Liquidity risk is the risk that Suncor will not be able to meet its financial obligations when due. The company mitigates this risk by forecasting spending requirements as well as cash flow from operating activities, and maintaining sufficient cash, credit facilities, and debt shelf prospectuses to meet these requirements. Suncor's cash and cash equivalents and total credit facilities at December 31, 2016 were $3.0 billion and $10.5 billion, respectively. Of Suncor's $10.5 billion in total credit facilities, $8.1 billion were available at December 31, 2016. In addition, Suncor has $2.0 billion of unused capacity under a Canadian debt shelf prospectus and an unused capacity of US$3.0 billion under a Canadian and U.S. universal shelf prospectus.

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

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

	December 31, 2015		
($ millions)	Trade and Other Payables[1]	Gross Derivative Liabilities[2]	Debt[3]
Within one year	5 218	1 629	1 725
1 to 3 years	20	—	5 062
3 to 3 years	29	—	1 456
Over 5 years	38	—	19 976
	5 305	1 629	28 219

	December 31, 2016		
($ millions)	**Trade and Other Payables[1]**	**Gross Derivative Liabilities[2]**	**Debt[3]**
Within one year	**5 379**	**1 819**	**2 325**
1 to 3 years	**28**	**—**	**5 238**
3 to 5 years	**14**	**—**	**3 031**
Over 5 years	**43**	**—**	**19 934**
	5 464	**1 819**	**30 528**

(1) Trade and other payables exclude net derivative liabilities of $209 million (2015 – $88 million)

(2) Gross derivative liabilities of $1 819 million (2015 – $1 629 million) are offset by gross derivative assets of $1 610 million (2015 – $1 541 million), resulting in a net amount of $209 million (2015 – $88 million).

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

3) Credit Risk

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

A substantial portion of the company's accounts receivable are with customers in the oil and gas industry and are subject to normal industry credit risk. While the industry has experienced significant credit downgrades in the past year, Suncor has not been significantly affected as the majority of Suncor's customers are large, established downstream companies

whose financial position is not directly tied to the benchmark price of crude oil. At December 31, 2016, substantially all of the company's trade receivables were current.

The company may be exposed to certain losses in the event that counterparties to derivative financial instruments are unable to meet the terms of the contracts. The company's exposure is limited to those counterparties holding derivative contracts owing to the company at the reporting date. At December 31, 2016, the company's exposure was $1 765 million (December 31, 2015 – $1 631 million).

29. CAPITAL STRUCTURE FINANCIAL POLICIES

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

The company's capital is primarily monitored by reviewing the ratios of net debt to funds from operations [(1)] and total debt to total debt plus shareholders' equity.

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

Total debt to total debt plus shareholders' equity is calculated as short-term debt plus total long-term debt divided by short-term debt plus total long-term debt plus shareholders' equity. This financial covenant under the company's various banking and debt agreements shall not be greater than 65%.

The company's financial covenant is reviewed regularly and controls are in place to maintain compliance with the covenant. The company complied with financial covenants for the years ended December 31, 2016 and 2015. The company's financial measures, as set out in the following schedule, were unchanged from 2015. The company believes that achieving its capital target helps to provide the company access to capital at a reasonable cost by maintaining solid investment grade credit ratings. The company operates in a fluctuating business environment and ratios may periodically fall outside of management's targets. The company addresses these fluctuations by capital expenditure reductions and sales of non-core assets to ensure net debt achieves management's targets.

($ millions)	Capital Measure Target	**December 31, 2016**	December 31, 2015
Components of ratios			
Short-term debt		**1 273**	747
Current portion of long-term debt		**54**	70
Long-term debt		**16 103**	14 486
Total debt		**17 430**	15 303
Less: Cash and cash equivalents		**3 016**	4 049
Net debt		**14 414**	11 254
Shareholders' equity		**44 630**	39 039
Total capitalization (total debt plus shareholders' equity)		**62 060**	54 342
Funds from operations[(1)]		**5 988**	6 806
Net debt to funds from operations	<3.0 times	**2.4**	1.7
Total debt to total debt plus shareholders' equity		**28%**	28%

(1) Funds from operations is calculated as cash flow from operating activities before changes in non-cash working capital, and is a non-GAAP financial measure.

30. JOINT ARRANGEMENTS

Joint Operations

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

Material Joint Operations	Principal Activity	Country of Incorporation and Principal Place of Business	Ownership % 2016	Ownership % 2015
Oil Sands				
Operated by Suncor:				
Fort Hills Energy Limited Partnership	Oil sands development	Canada	50.80	50.80
Non-operated:				
Syncrude	Oil sands development	Canada	53.74	12.00
Exploration and Production				
Operated by Suncor:				
Terra Nova	Oil and gas production	Canada	37.68	37.68
Non-operated:				
White Rose and the White Rose Extensions	Oil and gas production	Canada	26.13-27.50	26.13-27.50
Hibernia and the Hibernia South Extension Unit	Oil and gas production	Canada	19.13-20.00	19.13-20.00
Hebron	Oil and gas production	Canada	21.03	22.73
Harouge Oil Operations	Oil and gas production	Libya	49.00	49.00
Buzzard	Oil and gas production	United Kingdom	29.89	29.89
Golden Eagle Area Development	Oil and gas production	United Kingdom	26.69	26.69
Oda	Oil and gas production	Norway	30.00	30.00

Joint Ventures and Associates

The company does not have any joint ventures or associates that are considered individually material. Summarized aggregate financial information of the joint ventures and associates, which are all included in the company's Refining and Marketing operations, are shown below:

	Joint ventures		Associates	
($ millions)	**2016**	2015	**2016**	2015
Net earnings (loss)	**1**	(14)	**(3)**	4
Other comprehensive income	**—**	9	**—**	—
Total comprehensive income (loss)	**1**	(5)	**(3)**	4
Carrying amount as at December 31	**45**	59	**93**	98

31. SUBSIDIARIES

Material subsidiaries, each of which is wholly owned, either directly or indirectly, by the company as at December 31, 2016, are shown below:

Material Subsidiaries	Principal Activity
Canadian Operations	
Suncor Energy Oil Sands Limited Partnership	This partnership holds most of the company's oil sands operations assets.
Suncor Energy Products Inc.	This subsidiary held interests in the company's energy marketing and renewable energy businesses.(1)
Suncor Energy Products Partnership	This partnership holds substantially all of the company's Canadian refining and marketing assets.
Suncor Energy Marketing Inc.	Through this subsidiary, production from the upstream Canadian businesses is marketed. This subsidiary also administers Suncor's energy trading activities and power business, markets certain third-party products, procures crude oil feedstock and natural gas for its downstream business, and procures and markets NGLs and LPG for its downstream business.
Suncor Energy Venture Holding Corporation	A subsidiary which owned a 36.74% ownership in the Syncrude joint operation previously owned by COS.(2)
Suncor Energy Ventures Partnership	A subsidiary which owns a 17% ownership in the Syncrude joint operation.
U.S. Operations	
Suncor Energy (U.S.A.) Marketing Inc.	A subsidiary that procures and markets third-party crude oil, in addition to procuring crude oil feedstock for the company's refining operations.
Suncor Energy (U.S.A.) Inc.	A subsidiary through which the company's U.S. refining and marketing operations are conducted.
International Operations	
Suncor Energy UK Limited	A subsidiary through which the majority of the company's North Sea operations are conducted.

(1) This subsidiary amalgamated into Suncor Energy Inc. on January 1, 2017.

(2) This subsidiary amalgamated into Suncor Energy Ventures Corporation on January 1, 2017.

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

32. RELATED PARTY DISCLOSURES

Related Party Transactions

The company enters into transactions with related parties in the normal course of business, which includes purchases of feedstock, distribution of refined products, and sale of refined products and by-products. These transactions are with joint ventures and associated entities in the company's Refining and Marketing operations, including pipeline, refined product and petrochemical companies. A summary of the significant related party transactions as at and for the year ended December 31, 2016 and 2015 are as follows:

($ millions)	2016	2015
Sales[1]	**667**	1 126
Purchases	**152**	201
Accounts receivable	**61**	73
Accounts payable and accrued liabilities	**42**	15

(1) Includes sales to Parachem Chemicals Inc. of $219 million (2015 – $295 million) and UPI Inc. of $226 million (2015 – $241 million). The company's remaining interest in UPI Inc. was sold during the fourth quarter of 2016 and is no longer a related party. Sales to UPI Inc. up to the closing date of October 31, 2016 have been included.

Compensation of Key Management Personnel

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

($ millions)	2016	2015
Salaries and other short-term benefits	**13**	12
Pension and other post-retirement benefits	**5**	5
Share-based compensation	**74**	39
	92	56

33. COMMITMENTS, CONTINGENCIES AND GUARANTEES

(a) Commitments

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

	Payment due by period						
($ millions)	2017	2018	2019	2020	2021	2022 and beyond	**Total**
Commitments							
Product transportation and storage	1 627	968	854	915	898	9 260	**14 522**
Energy services	220	178	223	161	156	473	**1 411**
Drilling commitments	3	—	—	—	—	—	**3**
Exploration work commitments	—	121	97	120	164	66	**568**
Other	335	125	77	48	48	173	**806**
Operating leases	551	460	355	309	267	1 468	**3 410**
	2 736	1 852	1 606	1 553	1 533	11 440	**20 720**

Significant operating leases expire at various dates through 2042. For the year ended December 31, 2016, operating lease expense was $699 million (2015 – $800 million). Included in the table above is $96 million of commitments pertaining to the company's lubricants business and Cedar Point wind facility, which were sold subsequent to December 31, 2016 (note 41).

In addition to the commitments in the above table, the company has other obligations for goods and services and raw materials entered into in the normal course of business, which may terminate on short notice. Such obligations include commodity purchase obligations which are transacted at market prices. The company has also entered into various pipeline commitments of $6.6 billion with contract terms up to 20 years, which are awaiting regulatory approval. In the event regulatory approval is not obtained, the company has committed to reimbursing certain costs to the service provider.

(b) Contingencies

Legal and Environmental Contingent Liabilities

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

The company may also have environmental contingent liabilities, beyond decommissioning and restoration liabilities (recognized in note 25), which are reviewed individually and are reflected in the company's consolidated financial statements if material and more likely than not to be incurred. These contingent environmental liabilities primarily relate to the mitigation of contamination at sites where the company has had operations. For any unrecognized environmental contingencies, the company believes that any liabilities that might arise pertaining to such matters would not have a material effect on its consolidated financial position.

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

Operational Risk

The company also has exposure to some operational risks, which is reduced by maintaining an insurance program.

The company carries property damage and business interruption insurance with varying coverage limits and deductible amounts based on the asset. As of December 31, 2016, Suncor's insurance program includes coverage of up to US$1.3 billion for oil sands risks, up to US$1.05 billion for offshore risks and up to US$1.3 billion for refining risks. These limits are all net of deductible amounts or waiting periods and subject to certain price and volume limits. The company also has primary property insurance for US$400 million that covers all of Suncor's assets. Suncor believes its liability, property and business interruption insurance is appropriate to its business, although such insurance will not provide coverage in all circumstances or fully protect against prolonged outages. In the future, the insurance program may change due to market conditions or other business considerations.

(c) Guarantees

At December 31, 2016, the company provides loan guarantees to certain retail licensees and wholesale marketers. Suncor's maximum potential amount payable under these loan guarantees is $125 million.

The company has also agreed to indemnify holders of all notes and debentures and the company's credit facility lenders (see note 22) for added costs relating to withholding taxes. Similar indemnity terms apply to certain facility and equipment leases. There is no limit to the maximum amount payable under these indemnification agreements. The company is unable to determine the maximum potential amount payable as government regulations and legislation are subject to change without notice. Under these agreements, the company has the option to redeem or terminate these contracts if additional costs are incurred.

The company also has guaranteed its working-interest share of certain joint venture undertakings related to transportation services agreements entered into with third parties. The guaranteed amount is limited to the company's share in the joint arrangement. As at December 31, 2016, the probability is remote that these guarantee commitments will impact the company.

34. OIL SANDS ASSET SWAP

On August 31, 2015, Suncor completed an exchange of assets with TransAlta Corporation (TransAlta). Suncor exchanged Kent Breeze and its 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 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 to finance the difference between the fair value of the cogeneration facilities and the fair value of the wind farms. 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.

The acquisition of the Poplar Creek assets was treated as a business combination, whereby the assets and liabilities acquired were recorded at their fair value. The fair value was calculated using an expected future cash flow approach with

a risk-adjusted discount rate of 8%. Key assumptions used in the calculation were discount rate, power price and natural gas price.

Purchase consideration

($ millions)

Fair value of wind assets	124
Fair value of deferred financing arrangement	303
Total purchase consideration	**427**

Purchase price allocation

The purchase price allocation is based on management's best estimates of the fair value of the acquired assets and assumed liabilities.

($ millions)

Working capital	36
Property, plant and equipment	393
Decommissioning provision	(2)
Net assets acquired	**427**

35. ROSEBANK ACQUISITION

On October 6, 2016, Suncor completed the purchase of a 30% interest in the U.K. North Sea Rosebank project from OMV (U.K.) Limited (OMV) for an initial payment of US$50 million to OMV. In the event the co-venturers approve the Rosebank project final investment decision and Suncor elects to participate, Suncor could pay additional consideration of up to US$165 million. As the additional consideration is dependent on Suncor approval of the final investment decision, no amount has been recognized at December 31, 2016.

36. ACQUISITION OF ADDITIONAL INTEREST IN FORT HILLS

During the fourth quarter of 2015, the company completed the purchase of an additional 10% working interest in the Fort Hills oil sands project from Total E&P Canada Ltd. for consideration of $360 million. Suncor's share of the project is now 50.8%.

37. FORT HILLS

The company has assessed the impact of the construction delay due to the forest fires in the second quarter of 2016, and other construction changes associated with the complexity and scale of secondary extraction detailed design development, and now estimates the overall cost of the Fort Hills' project to be between $16.5 and $17.0 billion. Suncor has also incurred an additional $160 million on the project due to changes in the Canadian dollar since the project was sanctioned. The increase in project costs is viewed as an indicator of impairment and the company performed an impairment test on its share of the project as at December 31, 2016. The impairment test was performed using a fair value less cost of disposal methodology, and no impairment was noted. An expected cash flow approach was used based on 2016 year end reserves data and long-range planning assumptions reviewed and approved by management, with the following assumptions (Level 3 fair value inputs):

- WCS price forecasts of C$56.40/bbl starting at first oil in late 2017, C$59.55/bbl in 2018, C$62.60/bbl in 2019, C$74.40 in 2020 and beyond, (expressed in real dollars), adjusted for asset specific location and quality differentials;
- risk adjusted discount rate of 7.5% (after-tax);
- production of approximately 94,500 barrels per day following a twelve-month ramp-up period starting late in the fourth quarter of 2017;

- go forward construction capital of $1.8 billion; and
- operating costs averaging approximately $23.40 per barrel over the life of the project (expressed in real dollars).

Based on the above assumptions, the estimated recoverable amount in respect of the company's interest in Fort Hills exceeds the carrying value. The recoverable amount is sensitive to changes in the key assumptions. Future changes in these assumptions, individually or in combination, could result in the recoverable amount being less than the carrying value and an impairment adjustment. A 5% decrease in the assumed realized prices would decrease the recoverable amount by approximately $1 billion. A 1% increase in the discount rate would decrease the recoverable amount by approximately $1.35 billion, a 5% increase in the estimated future operating costs would decrease the recoverable amount by $400 million and a 10% increase in the company's share of the remaining development capital would decrease the recoverable amount by $140 million (sensitivities are after-tax).

The carrying value of the company's share of the Fort Hills project at December 31, 2016 was $8.2 billion, including amounts allocated to the project at the time of the company's merger with Petro-Canada in 2009.

38. PIONEER DISPOSITION

During the third quarter of 2014, the company announced that, along with The Pioneer Group Inc., it had reached an agreement to sell the assets of Pioneer Energy, including retail gas stations in Ontario and Manitoba. The company's

investment in Pioneer was recorded at fair value and classified as an available for sale financial instrument. The transaction closed in the second quarter of 2015 and the company received $183 million for its 50% share of Pioneer Energy and realized an after-tax gain of $68 million in the Refining and Marketing segment.

39. ASSETS HELD FOR SALE

As at June 30, 2016, the company had reclassified the assets and liabilities related to its lubricants plant and associated infrastructure as assets held for sale. The lubricants business is reported within the Refining and Marketing segment. See note 41 for closing of sale.

The table below details the assets and liabilities of the lubricants business that were held for sale as at December 31, 2016:

($ millions)

Assets	
Accounts receivable	209
Prepaids	3
Inventories	258
Property, plant and equipment, net	428
Total assets	898
Liabilities	
Accounts payable and accrued liabilities	72
Income taxes payable	3
Pension liability	20
Deferred income taxes	71
Total liabilities	**166**

At September 30, 2016, the company has reclassified certain assets and liabilities related to its renewable energy business as assets held for sale. Suncor has commenced a sale process for these assets and anticipates that a sale could occur within the next nine months from December 31, 2016. The renewable energy business is reported within the Corporate segment. See note 41 for the sale of the Cedar Point wind facility, included in the assets and liabilities held for sale below.

The table below details the assets and liabilities of the renewable energy business that were held for sale as at December 31, 2016:

($ millions)	
Assets	
Accounts receivable	23
Property, plant and equipment, net	284
Total assets	307
Liabilities	
Accounts payable and accrued liabilities	12
Other long-term liabilities	10
Provisions	9
Total liabilities	**31**

40. SUSPENDED EXPLORATORY WELL COSTS

($ millions)	2016	2015
Beginning of year	**212**	346
Additions	**209**	—
Transfers to oil and gas assets	**(65)**	—
Capitalized exploratory well costs charged to expense	**(356)**	(134)
End of year	**—**	212

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

($ millions)	2016	2015
Suspended exploratory well costs that have been capitalized for a period less than one year	**—**	—
Suspended exploratory well costs that have been capitalized for a period greater than one year	**—**	212
	—	212
Number of suspended exploratory wells that have been capitalized for a period greater than one year	**—**	3

At December 31, 2016, there are no suspended capitalized costs for exploratory wells. Suspended capitalized costs for exploratory wells completed prior to December 31, 2015 are associated with projects located in Norway (three wells). During 2016, one well was transferred to oil and gas assets as the project received sanction, and two wells were impaired to zero carrying value due to uncertainty around plans for future development.

41. SUBSEQUENT EVENTS

On February 1, 2017, the company completed the sale of its Petro-Canada Lubricants Inc. (PCLI) business to a subsidiary of HollyFrontier Corporation (HollyFrontier) for gross proceeds of $1.125 billion, subject to customary post-closing adjustments. The sale includes PCLI's production and manufacturing centre in Mississauga, Ontario and the global marketing and distribution assets held by PCLI, including its global offices. Under the terms of the agreement, HollyFrontier will continue to operate the lubricants business under the Petro-Canada trademark. On January 24, 2017, the company completed the sale of its interest in the Cedar Point wind facility for gross proceeds of $291 million.

QuickLinks

EXHIBIT 99-1

Audited Consolidated Financial Statements of Suncor Energy Inc. for the fiscal year ended December 31, 2016

QuickLinks -- Click here to rapidly navigate through this document

EXHIBIT 99-2

**Management's Discussion and Analysis for the fiscal year ended December 31, 2016,
dated March 1, 2017**

MANAGEMENT'S DISCUSSION AND ANALYSIS

March 1, 2017

This Management's Discussion and Analysis (this MD&A) should be read in conjunction with Suncor's December 31, 2016 audited Consolidated Financial Statements and the accompanying notes. Additional information about Suncor filed with Canadian securities regulatory authorities and the United States Securities and Exchange Commission (SEC), including quarterly and annual reports and Suncor's Annual Information Form dated March 1, 2017 (the 2016 AIF), which is also filed with the SEC under cover of Form 40-F, is available online at www.sedar.com, www.sec.gov and our website, www.suncor.com. Information on or connected to our website, even if referred to in this MD&A, does not constitute part of this MD&A.

References to "we", "our", "Suncor", or "the company" mean Suncor Energy Inc., its subsidiaries, partnerships and joint arrangements, unless the context requires otherwise. For a list of abbreviations that may be used in this MD&A, refer to the Advisories – Common Abbreviations section of this MD&A.

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Basis of Presentation

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

All financial information is reported in Canadian dollars, unless otherwise noted. Production volumes are presented on a working-interest basis, before royalties, unless otherwise noted.

Non-GAAP Financial Measures

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

Measurement Conversions

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

Common Abbreviations

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

Risks and Forward-Looking Information

The company's financial and operational performance is potentially affected by a number of factors, including, but not limited to, the factors described in the Risk Factors section of this MD&A.

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

1. FINANCIAL AND OPERATING SUMMARY

Financial Summary

Year ended December 31 ($ millions, except per share amounts)	2016	2015	2014
Operating revenues, net of royalties	**26 807**	29 208	39 862
Net earnings (loss)	**445**	(1 995)	2 699
per common share – basic	**0.28**	(1.38)	1.84
per common share – diluted	**0.28**	(1.38)	1.84
Operating (loss) earnings[1]	**(83)**	1 465	4 620
per common share – basic	**(0.05)**	1.01	3.15
Funds from operations[2]	**5 988**	6 806	9 058
per common share – basic	**3.72**	4.71	6.19
Cash flow provided by operating activities	**5 680**	6 884	8 936
per common share – basic	**3.53**	4.76	6.11
Dividends paid on common shares	**1 877**	1 648	1 490
per common share – basic	**1.16**	1.14	1.02
Weighted average number of common shares in millions – basic	**1 610**	1 446	1 462
Weighted average number of common shares in millions – diluted	**1 612**	1 447	1 465
ROCE[1][3] (%)	**0.5**	0.6	8.6
Capital Expenditures[4]	**5 986**	6 220	6 530
Sustaining	**2 275**	2 602	3 014
Growth	**3 711**	3 618	3 516
Discretionary free cash flow[1]	**1 797**	2 556	4 554
Balance Sheet (at December 31)			
Total assets	**88 702**	77 527	79 671
Long-term debt[5]	**16 157**	14 556	12 523
Net debt	**14 414**	11 254	7 834
Total liabilities	**44 072**	38 488	38 068

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

(2) Funds from operations was previously referred to as cash flow from operations, with the calculation being unchanged from prior years. Funds from operations is a non-GAAP financial measure. See the Advisories – Non-GAAP Financial Measures section of this MD&A.

(3) ROCE excludes capitalized costs related to major projects in progress.

(4) Excludes capitalized interest.

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

Operating Summary

Year ended December 31	**2016**	2015	2014
Production Volumes (mboe/d)			
Oil Sands	**504.9**	463.4	421.9
Exploration and Production	**117.9**	114.4	113.0
Total	**622.8**	577.8	534.9
Production Mix			
Crude oil and liquids / natural gas (%)	**99/1**	99/1	99/1
Average Price Realizations[1] ($/boe)			
Oil Sands operations	**39.97**	48.78	86.57
Syncrude	**56.38**	59.74	96.06
Exploration and Production	**53.34**	60.53	103.05
Refinery crude oil processed (mbbls/d)	**428.6**	432.1	427.5
Refinery Utilization[2] (%)			
Eastern North America	**92**	94	90
Western North America	**94**	93	95
	93	94	93

(1) Net of transportation costs, but before royalties.

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

Segment Summary

Year ended December 31 ($ millions)	**2016**	2015	2014
Net (loss) earnings			
Oil Sands	**(1 149)**	(856)	1 776
Exploration and Production	**190**	(758)	653
Refining and Marketing	**1 890**	2 306	1 692
Corporate, Energy Trading and Eliminations	**(486)**	(2 687)	(1 422)
Total	**445**	(1 995)	2 699
Operating (loss) earnings[1]			
Oil Sands	**(1 109)**	(111)	2 771
Exploration and Production	**10**	7	857
Refining and Marketing	**1 890**	2 274	1 692
Corporate, Energy Trading and Eliminations	**(874)**	(705)	(700)
Total	**(83)**	1 465	4 620
Funds from (used in) operations[2]			
Oil Sands	**2 669**	2 835	5 400
Exploration and Production	**1 313**	1 386	1 909
Refining and Marketing	**2 606**	2 921	2 178
Corporate, Energy Trading and Eliminations	**(600)**	(336)	(429)
Total	**5 988**	6 806	9 058
Cash flow provided by (used in) operating activities			
Oil Sands	**2 286**	2 808	6 652
Exploration and Production	**1 373**	1 708	2 110
Refining and Marketing	**3 393**	3 227	1 956
Corporate, Energy Trading and Eliminations	**(1 372)**	(859)	(1 782)
Total	**5 680**	6 884	8 936

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

(2) Funds from (used in) operations was previously referred to as cash flow from (used in) operations, with the calculation being unchanged from prior years. Funds from (used in) operations is a non-GAAP financial measure. See the Advisories – Non-GAAP Financial Measures section of this MD&A.

2. SUNCOR OVERVIEW

Suncor is an integrated energy company headquartered in Calgary, Alberta, Canada. We are strategically focused on developing one of the world's largest petroleum resource basins – Canada's Athabasca oil sands. In addition, we explore for, acquire, develop, produce and market crude oil and natural gas in Canada and internationally; we transport and refine crude oil, and we market petroleum and petrochemical products primarily in Canada. We also conduct energy trading activities focused principally on the marketing and trading of crude oil, natural gas and byproducts. We also operate a renewable energy business as part of our overall portfolio of assets.

For a description of Suncor's business segments, refer to the Segment Results and Analysis section of this MD&A.

Suncor's Strategy

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

- Profitably operate and develop our reserves – Suncor's growth and development plan is focused on projects and initiatives, such as Fort Hills and asset optimization with Syncrude, that are expected to provide long-term profitability for the company. The company's significant reserves base and industry expertise in oil sands has laid the groundwork for achieving this growth. Suncor's economies of scale have also allowed us to focus on near-term oil sands growth through low-cost efficiency improvements and expansion projects.

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

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

- Industry leader in sustainable development – Suncor is focused on triple bottom line sustainability, which means leadership and industry collaboration in environmental performance, social responsibility and creating a strong economy.

2016 Highlights

Financial results summary

- The company's financial results are primarily driven by record upstream crude oil sales of 628,700 bbls/d in 2016 at an average realized price of $49.11/bbl and total refined product sales of 521,400 bbls/d.

- Net earnings for 2016 were $445 million, compared to a net loss of $1.995 billion in 2015.

- Operating loss[(1)] for 2016 was $83 million, compared to operating earnings of $1.465 billion in 2015.

- Cash flow provided by operating activities, which includes changes in non-cash working capital, for 2016 was $5.680 billion, compared to $6.884 billion in 2015.

- Funds from operations[(2)] for 2016 was $5.988 billion, compared to $6.806 billion in 2015.

- ROCE[(1)] (excluding major projects in progress) was 0.5% for 2016, compared to 0.6% for 2015. ROCE for 2015 improves to 4.2% when removing the impacts of impairment charges.

The strength of Suncor's balance sheet allowed the company to complete the acquisitions of additional working interests in Syncrude in 2016, increasing Suncor's ownership interest to 53.74%.

- Acquired Canadian Oil Sands Limited (COS) in the first quarter of 2016, adding 128,600 bbls/d of synthetic crude oil (SCO) capacity. The transaction was valued at $6.9 billion.

- Acquired an additional 5% interest in Syncrude from Murphy Oil Company Ltd. (Murphy) for $946 million in the second quarter of 2016, adding an additional 17,500 bbls/d of SCO capacity.

- The company completed a common share offering for net proceeds of $2.8 billion to fund the acquisition of Murphy's 5% interest in Syncrude and to reduce debt to provide ongoing balance sheet flexibility.

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(1) Non-GAAP financial measures. See the Advisories – Non-GAAP Financial Measures section of this MD&A.
(2) Funds from operations was previously referred to as cash flow from operations, with the calculation being unchanged from prior years. Funds from operations is a non-GAAP financial measure. See the Advisories – Non-GAAP Financial Measures section of this MD&A.

Oil Sands production increased 9%, despite the production outages at Oil Sands operations and Syncrude due to the Fort McMurray forest fires.

- Oil Sands operations successfully returned to normal production rates following the production shut-in due to the forest fires in the Fort McMurray region in the second quarter of 2016 and averaged 374,800 bbls/d for the year. When excluding the impact of the second quarter, upgrader utilization averaged 90%.

- 2016 Syncrude production increased to 130,100 bbls/d, from 29,800 bbls/d in 2015. The increase is a result of additional working interests acquired in 2016 combined with significantly improved upgrader reliability. Syncrude upgrader utilization improved to 78% in 2016, compared to 71% in 2015, and was significantly impacted by the production outage associated with the forest fires in the second quarter of 2016. Excluding the impact of the second quarter, upgrader utilization was 97%.

Significant progress on key growth projects, Fort Hills and Hebron, continued in 2016.

- The Fort Hills project was more than 76% complete at the end of 2016, with the remaining work to be based at site near Fort McMurray. The secondary extraction module construction program has been completed, with construction in secondary extraction and utilities achieving peak activity in the year. The company has assessed cost pressures on the project and now estimates the overall cost of the Fort Hills project to be between $16.5 and $17.0 billion. Suncor's share of Fort Hills' remaining project capital is between $1.6 and $1.8 billion. The majority of the spend will occur in 2017 and will be completed within Suncor's existing capital guidance range. In addition, the company has increased the nameplate capacity to 194,000 bbls/d after optimization and technical review. With these changes, Suncor's total capital intensity is expected to remain consistent with the original sanction estimate of $84,000 per flowing barrel of bitumen. First oil continues to remain on track for late 2017.

- Construction of the Hebron project continued in 2016, achieving significant project milestones on schedule. The integrated topsides were towed out to the deepwater construction site and successfully mated with the gravity-based structure in the fourth quarter. First oil from the project continues to be on track for late 2017.

Suncor successfully executed its plan to divest of non-core assets and has entered into agreements for anticipated proceeds of $2.0 billion, exceeding the $1.0 to $1.5 billion target established at the start of 2016.

- Suncor reached an agreement to sell its lubricants business for gross proceeds of $1.125 billion in the fourth quarter of 2016, with the transaction closing on February 1, 2017.

- On January 24, 2017, Suncor completed the sale of its interest in the Cedar Point wind facility for gross proceeds of $291 million.

- In the third quarter of 2016, participation agreements were signed with the Fort McKay and Mikisew Cree First Nations for the sale of a combined 49% interest in the East Tank Farm (ETF) development for estimated proceeds of approximately $500 million. These transactions are expected to close in the third quarter of 2017.

The Refining and Marketing (R&M) segment continued to deliver strong results in 2016.

- Stronger product location and crude differentials, solid operational performance and continued cost management helped to partially offset significantly lower benchmark crack spreads, which declined by approximately 30% compared to 2015. Results also benefited from a first-in, first-out (FIFO) gain of $111 million, as compared to a FIFO loss of $286 million in the prior year.

Exploration and Production (E&P) delivered another year of reliable, low-cost operations in 2016 and has advanced significant growth opportunities.

- Increased production combined with lower operating costs helped to offset the impact of a 17% decline in benchmark crude pricing from 2015 to 2016 and maintain strong funds from operations[(1)].

- In addition to making significant progress on Hebron, the company has advanced new development opportunities with the sanction of the Oda field in Norway and the acquisition of a participating interest in the Rosebank development in the U.K.

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Suncor's focus on cost management, capital discipline and operational excellence resulted in funds from operations [1] significantly exceeding sustaining capital and dividends in the year.

- Discretionary free cash flow[2] for 2016 was $1.8 billion, which represents funds from operations after sustaining capital, inclusive of associated capitalized interest, and dividends.
- The disciplined execution of Suncor's 2016 capital plan resulted in Suncor ending the year within the revised guidance range of $5.8 billion to $6.0 billion, which represents a decrease of over $1.0 billion from the midpoint of the original guidance.
- The company's cost reduction initiatives generated significant savings in the period, reducing 2016 operating expenses by approximately $850 million, after normalizing for the impact of the Syncrude acquisitions.

Cash operating costs per barrel reduced at both Oil Sands operations and Syncrude, despite the decreases in production associated with the forest fires in the second quarter.

- Oil Sands operations cash operating costs per barrel [2] decreased from $27.85/bbl in 2015 to $26.50/bbl in 2016, which is the lowest since 2007. The decrease is a result of Suncor's cost reduction initiatives and lower natural gas prices, however; the full impact was partially offset by decreased production associated with the forest fires.
- Syncrude's cash operating costs per barrel[2] decreased from $42.00/bbl in 2015 to $35.95/bbl in 2016, a decrease of close to 15%, despite the impact to production associated with the forest fires in the second quarter. The decrease is due to increased production combined with lower cash operating costs.

Suncor continued to return cash to shareholders through dividends in 2016.

- The company paid $1.877 billion in dividends in 2016, marking the fourteenth consecutive year Suncor's annual dividend has increased.
- Subsequent to the end of the year, Suncor's Board of Directors approved a 10% increase to the company's dividend from $0.29 to $0.32 per common share, demonstrating the company's commitment and ability to generate cash flow and return cash to shareholders, even in a low commodity price environment.

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

3. FINANCIAL INFORMATION

Net Earnings

Suncor's net earnings in 2016 were $445 million, compared to a net loss of $1.995 billion in 2015. Net earnings were impacted by the same factors that influenced operating earnings, which are described below. Other items affecting net earnings in 2016 and the net loss in 2015 included:

- The after-tax unrealized foreign exchange gain on the revaluation of U.S. dollar denominated debt was $524 million for 2016, compared to an after-tax loss of $1.930 billion for 2015.
- In 2016, the U.K. government enacted a decrease in the supplementary charge on oil and gas profits in the North Sea that reduced the statutory tax rate on Suncor's earnings in the U.K. from 50% to 40%, effective January 1, 2016. The company revalued its January 1, 2016 deferred income tax balances, resulting in a deferred income tax recovery of $180 million in the E&P segment.
- In 2016, the company incurred a non-cash after-tax charge of $73 million in the Corporate segment for early payment of long-term debt acquired as part of the COS acquisition.
- In 2016, the company recorded after-tax derecognition charges of $40 million on certain upgrading and logistics assets in the Oil Sands segment, as well as $31 million in the Corporate segment relating to an initial investment in an undeveloped pipeline and on certain renewable energy development assets, as a result of the uncertainty of future benefits from these assets.
- The company incurred $38 million in after-tax charges in the Corporate segment in 2016 associated with the acquisition and integration of COS.
- In 2015, the company recorded after-tax impairment charges against property, plant and equipment and exploration and evaluation assets of $359 million on White Rose, $331 million on Golden Eagle and $54 million on Terra Nova, primarily as a result of impacts of a decline in the crude oil price forecast. In addition, impairment charges of $290 million were recorded against the Joslyn mining project and $54 million on the Ballicatters well, due to uncertainty on the timing and likelihood of development plans, and $96 million in Oil Sands following a review of certain assets that no longer fit with Suncor's growth strategies, and which could not be repurposed or otherwise deployed.
- In 2015, the company recorded a $423 million deferred income tax charge related to a 2% increase in the Alberta corporate income tax rate.
- In 2015, as a result of shut-in production due to the continued closure of certain Libyan export terminals, escalating political unrest, and increased uncertainty with respect to the company's return to normal operations in the country, the company recorded an after-tax impairment charge of $415 million against property, plant and equipment and exploration and evaluation assets.
- In 2015, the company recorded a $406 million deferred income tax recovery in the E&P segment related to a reduction in the U.K. tax rate from 62% to 50%.
- In 2015, Suncor recorded after-tax insurance proceeds of $75 million related to a claim on the Terra Nova asset in the E&P segment.
- In 2015, the company recorded an after-tax gain of $68 million on the disposal of the company's share of certain assets and liabilities of Pioneer Energy in the R&M segment.
- In 2015, the company recorded after-tax restructuring charges of $57 million related to cost reduction initiatives in the Corporate segment.

Operating Earnings

Consolidated Operating (Loss) Earnings Reconciliation [1]

Year ended December 31 ($ millions)	2016	2015	2014
Net earnings (loss) as reported	**445**	(1 995)	2 699
Unrealized foreign exchange (gain) loss on U.S. dollar denominated debt	**(524)**	1 930	722
Derecognition and impairments net of reversals and provisions [2]	**71**	1 599	1 238
Non-cash mark to market gain on interest rate swap	**(6)**	—	—
Impact of income tax adjustments on deferred income taxes [3]	**(180)**	17	54
Non-cash loss on early payment of long-term debt	**73**	—	—
COS acquisition and integration costs	**38**	—	—
Restructuring charges	**—**	57	—
Recognition of insurance proceeds	**—**	(75)	—
Gain on significant disposals [4]	**—**	(68)	(61)
Reserves redetermination [5]	**—**	—	(32)
Operating (loss) earnings [1]	**(83)**	1 465	4 620

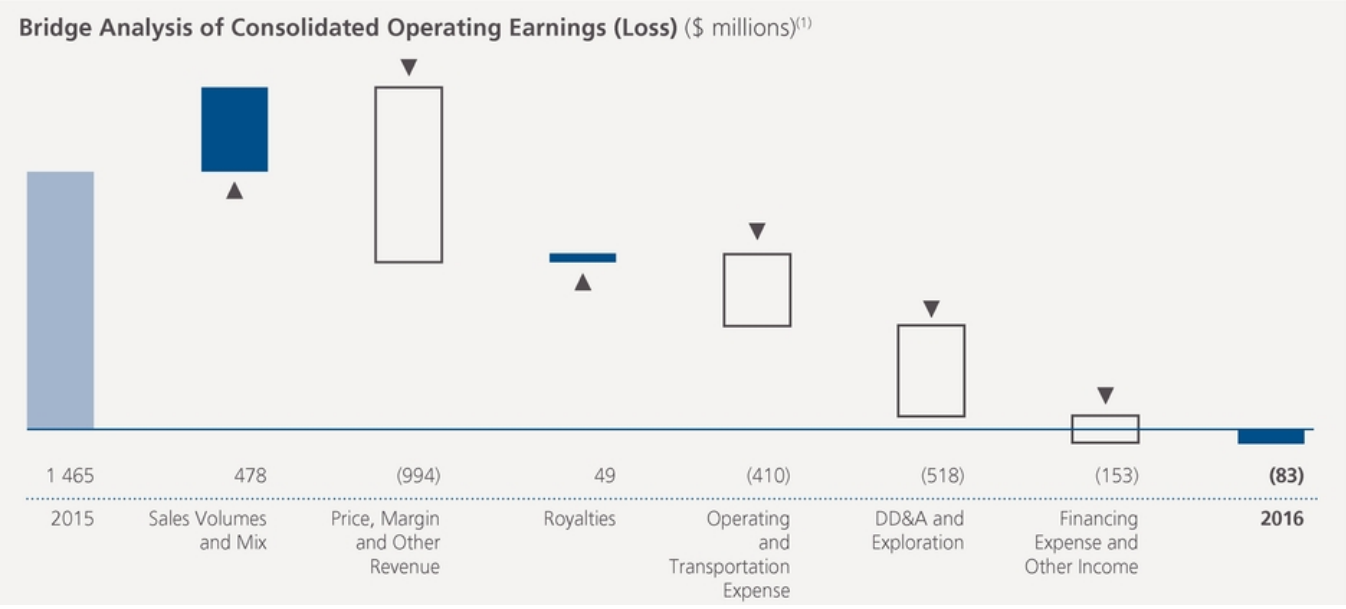
(1) Non-GAAP financial measure. See the Advisories – Non-GAAP Financial Measures section of this MD&A.

(2) In 2014, Suncor recorded an after-tax impairment charge to net earnings of $718 million against property, plant and equipment and exploration and evaluation assets related to the Joslyn mining project, as a result of Suncor's assessment of expected future net cash flows combined with the uncertainty of the project. Also in 2014, as a result of the continued closure of certain Libyan export terminals and the company's view on production plans during the remaining term of the production sharing agreements, the company recorded an after-tax impairment charge of $297 million against property, plant and equipment and exploration and evaluation assets. The company also recorded after-tax impairment charges of $223 million in the Oil Sands segment in 2014 following a review of certain assets that no longer fit with Suncor's previously revised growth strategies and which could not be repurposed or otherwise deployed. Such assets included a pipeline and related compressor, as well as steam generator components.

(3) In 2014, Suncor recorded a current income tax expense adjustment and associated interest expense of $54 million related to the timing of tax depreciation deductions taken on certain capital expenditures incurred in a prior period in the Oil Sands segment.

(4) In 2014, the company recorded an after-tax gain of $61 million relating to the sale of its Wilson Creek natural gas assets in the E&P segment.

(5) In 2014, the company recorded after-tax earnings of $32 million related to an agreement reached for Suncor to receive a reserves redetermination of 1.2 million barrels of oil related to an interest in a Norwegian asset that Suncor previously owned.



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

Suncor's consolidated operating loss in 2016 was $83 million, compared to operating earnings of $1.465 billion in the prior year. The decrease was primarily due to lower upstream price realizations in the first nine months of 2016, consistent with the decline in benchmark crude prices, the impact of shut-in production associated with the forest fires in the Fort McMurray area in the second quarter of 2016 and weaker benchmark crack spreads. These factors were partially offset by lower operating costs across the company's operations, a FIFO gain in downstream operations, when compared to a FIFO loss in the prior year, higher refined product location differentials and higher E&P production. Significantly increased production from Syncrude due to the acquisition of additional working interests in 2016 combined with improved upgrader reliability in the second half of the year was offset by the additional operating expenses and DD&A associated with increased production, as well as the production shut-in due to the forest fires.

Funds from Operations[1]

Consolidated funds from operations for 2016 were $5.988 billion, compared to $6.806 billion in 2015. Funds from operations were impacted by the same factors as operating earnings, after removing the impact of non-cash expenses primarily related to DD&A.

Results for 2015 compared with 2014

Net loss in 2015 was $1.995 billion, compared to net earnings of $2.699 billion in 2014. The decrease in net earnings was mainly due to the same factors impacting operating earnings described below and by the net earnings adjustments described above.

Operating earnings for 2015 were $1.465 billion, compared to $4.620 billion in 2014. The decrease was primarily due to lower operating earnings in the Oil Sands and E&P segments as a result of significantly lower upstream price realizations consistent with the decline in benchmark crude oil prices, partially offset by increased Oil Sands operations production due to improved reliability, record R&M operating earnings due to a strong downstream pricing environment and lower operating costs companywide.

Consolidated funds from operations for 2015 were $6.806 billion, compared to $9.058 billion in 2014. Funds from operations were impacted by the same factors as operating earnings.

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(1) Funds from operations was previously referred to as cash flow from operations, with the calculation being unchanged from prior years. Funds from operations is a non-GAAP financial measure. See the Advisories – Non-GAAP Financial Measures section of this MD&A.

Business Environment

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

Average for the year ended December 31	**2016**	2015	2014
WTI crude oil at Cushing (US$/bbl)	**43.35**	48.75	93.00
Dated Brent Crude (US$/bbl)	**43.75**	52.40	98.85
Dated Brent/Maya FOB price differential (US$/bbl)	**7.50**	9.50	13.70
MSW at Edmonton (Cdn$/bbl)	**51.90**	57.60	94.85
WCS at Hardisty (US$/bbl)	**29.55**	35.25	73.60
Light/heavy differential for WTI at Cushing less WCS at Hardisty (US$/bbl)	**13.85**	13.50	19.40
Condensate at Edmonton (US$/bbl)	**42.50**	47.35	92.95
Natural gas (Alberta spot) at AECO (Cdn$/mcf)	**2.15**	2.65	4.50
Alberta Power Pool Price (Cdn$/MWh)	**18.20**	33.40	49.65
New York Harbor 3-2-1 crack (1) (US$/bbl)	**14.05**	19.70	19.65
Chicago 3-2-1 crack (1) (US$/bbl)	**12.60**	18.50	17.40
Portland 3-2-1 crack (1) (US$/bbl)	**16.50**	25.15	20.15
Gulf Coast 3-2-1 crack (1) (US$/bbl)	**13.40**	18.35	16.50
Exchange rate (US$/Cdn$)	**0.75**	0.78	0.91
Exchange rate (end of period) (US$/Cdn$)	**0.74**	0.72	0.86

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

Suncor's sweet SCO price realizations are influenced primarily by the price of WTI at Cushing and by the supply and demand of sweet SCO from Western Canada. WTI decreased to US$43.35/bbl in 2016, compared to US$48.75/bbl in 2015.

Suncor also produces a specific grade of sour SCO, the price realizations for which are influenced by various crude benchmarks including, but not limited to, MSW at Edmonton and WCS at Hardisty, and which can also be affected by prices negotiated for spot sales. Prices for both MSW at Edmonton and WCS at Hardisty decreased in 2016 compared to 2015, resulting in lower realizations for sour SCO.

Bitumen production that Suncor does not upgrade is blended with diluent to facilitate delivery on pipeline systems. Net bitumen price realizations are therefore influenced by both prices for Canadian heavy crude oil (WCS at Hardisty is a common reference) and prices for diluent (Condensate at Edmonton and SCO) and pipeline tolls. Bitumen price realizations can also be affected by bitumen quality and spot sales.

Suncor's price realizations for production from East Coast Canada and E&P International assets are influenced primarily by the price for Brent crude. Brent crude pricing decreased over the prior year and averaged US$43.75/bbl in 2016, compared to US$52.40/bbl in 2015.

Suncor's price realizations for E&P Canada natural gas production are primarily referenced to Alberta spot at AECO. Natural gas is also used in the company's Oil Sands and Refining operations. The average AECO benchmark decreased to $2.15/mcf in 2016, from $2.65/mcf in 2015.

Suncor's refining margins are influenced by 3-2-1 crack spreads, which are industry indicators approximating the gross margin on a barrel of crude oil that is refined to produce gasoline and distillate, and by light/heavy and light/sour crude differentials. More complex refineries can earn greater margins by processing less expensive, heavier crudes. Crack spreads do not necessarily reflect the margins of a specific refinery. Crack spreads are based on current crude feedstock prices whereas actual refining margins are based on FIFO, where a delay exists between the time that feedstock is purchased and when it is processed and sold to a third party. Specific refinery margins are further impacted by actual crude purchase costs, refinery configuration and refined products sales markets unique to that refinery. Average market crack spreads decreased in 2016 compared to 2015, resulting in a negative impact to refining margins.

Excess electricity produced in Suncor's Oil Sands business is sold to the Alberta Electric System Operator (AESO), with the proceeds netted against the cash operating costs per barrel metric. The Alberta power pool price decreased to an average of $18.20/MWh in 2016 from $33.40/MWh in the prior year.

The majority of Suncor's revenues from the sale of oil and natural gas commodities are based on prices that are determined by or referenced to U.S. dollar benchmark prices. The majority of Suncor's expenditures are realized in Canadian dollars. 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. In 2016, the Canadian dollar weakened in relation to the U.S. dollar as the average exchange rate decreased to 0.75 from 0.78, which had a positive impact on price realizations for the company in 2016.

Conversely, many of Suncor's assets and liabilities, notably 75% of the company's debt, are denominated in U.S. dollars and translated to Suncor's reporting currency (Canadian dollars) at each balance sheet date. A decrease in the value of the Canadian dollar relative to the U.S. dollar from the previous balance sheet date increases the amount of Canadian dollars required to settle U.S. dollar denominated obligations.

Economic Sensitivities[1][2]

The following table illustrates the estimated effects that changes in certain factors would have had on 2016 net earnings and funds from operations [3] if the listed changes had occurred.

(Estimated change, in $ millions)	Net Earnings	Funds From Operations[3]
Crude oil +US$1.00/bbl	205	205
Natural gas +Cdn$0.10/mcf	(15)	(15)
Light/heavy differential +US$1.00/bbl	15	15
3-2-1 crack spreads +US$1.00/bbl	125	125
Foreign exchange +$0.01 US$/Cdn$ related to operating activities [4]	(130)	(130)
Foreign exchange on U.S. denominated debt +$0.01 US$/Cdn$	150	—

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

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

(3) Funds from operations was previously referred to as cash flow from operations, with the calculation being unchanged from prior years. Funds from operations is a non-GAAP financial measure. See the Advisories – Non-GAAP Financial Measures section of this MD&A.

(4) Excludes the foreign exchange impact on U.S. denominated debt.

4. SEGMENT RESULTS AND ANALYSIS

Suncor has classified its operations into the following segments:

OIL SANDS

Suncor's Oil Sands segment, with assets located in the 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 is comprised of:

- **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 Tailings Reduction Operations (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 such as Suncor's ETF operations. In Situ production is either upgraded by Oil Sands Base, or blended with diluent and marketed directly to customers. The ETF facility is currently being expanded to blend planned Fort Hills bitumen production for Suncor and the other Fort Hills project partners. Suncor has entered into participation agreements with Fort McKay and Mikisew Cree First Nations for the sale of a combined 49% interest in the new terminal assets once they are placed in service.

- **Oil Sands ventures** operations include Suncor's 50.8% interest in the Fort Hills mining project, where Suncor is the operator, and its 53.74% working interest in the Syncrude oil sands mining and upgrading joint operation. The company's interest in Syncrude increased from 12% as a result of the acquisition of COS, and the purchase of an additional 5% interest from Murphy during 2016. Suncor also holds a 36.75% interest in the idled Joslyn North mining prospect.

EXPLORATION AND PRODUCTION

Suncor's 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 non-operated interests in Hibernia (20% in the base project and 19.132% in the Hibernia Southern Extension Unit (HSEU)), White Rose (27.5% in the base project and 26.125% in the extensions), and the Hebron project (21.034%). 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 non-operated interests in Buzzard (29.89%), Golden Eagle Area Development (26.69%), the Rosebank future development project acquired in 2016 (30%) and the Oda project (30%). The first three projects are located in the U.K. sector of the North Sea, while the Oda project is located in the southern part of the Norwegian North Sea. Suncor also holds interests in several exploration licences offshore the U.K. and Norway. Suncor owns, pursuant to Exploration and Production Sharing Agreements (EPSAs), working interests in the exploration and development of oilfields in the Sirte Basin in Libya. Production in Libya remained substantially shut in through the majority of 2016 due to political unrest, with the timing of a return to normal operations remaining uncertain. Suncor also owns, pursuant to a Production Sharing Contract (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 R&M 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 and a refinery located in Sarnia, Ontario. Suncor previously operated a lubricants business located in Mississauga, Ontario that manufactured and blended products which were marketed worldwide. During 2016, Suncor entered into an agreement to sell its lubricants business, and the sale closed on February 1, 2017.

    - **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 in Montreal, Quebec, product pipelines and terminals in Canada and the U.S., and the St. Clair ethanol plant in Ontario.

- **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.

CORPORATE, ENERGY TRADING AND ELIMINATIONS

The grouping **Corporate, Energy Trading and Eliminations** includes the company's investments in renewable energy projects, results related to energy marketing, supply and trading activities, and other activities not directly attributable to any other operating segment.

- **Renewable Energy** investment activities include development, construction and ownership of Suncor-operated and joint venture partner-operated renewable power facilities across Canada. This includes a portfolio of operating wind power facilities located in Alberta, Saskatchewan and Ontario, as well as a portfolio of optioned lands for future wind and solar power project development. In 2016, Suncor entered into an agreement to sell its 50% share of the Cedar Point wind facility. The transaction closed on January 24, 2017.

- **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 **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.

OIL SANDS

2016 Highlights

- Oil Sands operations production was 374,800 bbls/d in 2016 and was significantly impacted by the forest fires in the Fort McMurray region in the second quarter of 2016, with production being shut in during this time.
- Acquired COS, including its 36.74% share of Syncrude, as well as Murphy's 5% interest in Syncrude, adding 146,100 bbls/d of synthetic crude oil capacity. Suncor's share of Syncrude is now 53.74%.
- Syncrude production increased to 130,100 bbls/d from 29,800 bbls/d in the prior year, as a result of additional working interests acquired in 2016, combined with improved upgrader reliability, partially offset by the production shut-in due to the Fort McMurray forest fires. Cash operating costs per barrel at Syncrude decreased to $35.95 from $42.00 in the prior year.
- In Situ operations demonstrated strong reliability in 2016 and set production records during both the first and fourth quarters, with 235,800 bbls/d and 238,400 bbls/d, respectively.
- Successful turnaround execution in 2016, with safety and cost results representing best turnaround performance to date.
- The company's continued focus on cost management enabled Suncor to decrease its Oil Sands operations cash operating costs per barrel by 5% to $26.50/bbl in 2016, compared to $27.85/bbl in the prior year and is the lowest achieved in close to a decade, despite the loss of production associated with the forest fires.
- Fort Hills construction reached peak activity in 2016 and was over 76% complete by the end of the year, with the remaining work to be based at site near Fort McMurray. After optimization and technical review, the company has increased the nameplate capacity of the Fort Hills project to 194,000 bbls/d. First oil is expected late in 2017.
- Participation agreements signed with the Fort McKay and Mikisew Cree First Nations for the sale of a combined 49% interest in the ETF development for estimated proceeds of approximately $500 million.

Strategy and Investment Update

Suncor continues to deliver on its commitment to add shareholder value and invest in long-term profitable growth in its core asset areas. In 2016, the company acquired an additional 41.74% working interest in the Syncrude oil sands asset from COS and Murphy. Suncor's share in the project is now 53.74%.

Oil Sands operations has established a large contiguous asset base providing the opportunity for production growth through low-cost integration, debottlenecks, expansions and increased reliability. Oil Sands operations and Syncrude's regional expertise and asset base will be leveraged to advance the Syncrude joint operation and to improve upon existing synergies through asset integration.

The company signed participation agreements with the Fort McKay and Mikisew Cree First Nations in 2016 for the sale of a combined 49% interest in the ETF development, underscoring Suncor's commitment to developing mutually beneficial long-term relationships with Aboriginal communities.

Oil Sands operations continues to focus on safe, reliable and sustainable operations. The company's operational excellence initiatives target improving facility utilization and workforce productivity, including a continued focus on upgrader reliability and achieving steady production growth while reducing operating costs. Sustaining capital for Oil Sands operations in 2017 is expected to include well pad development and major turnaround spending at Firebag and planned maintenance at Oil Sands Base for maintaining current production levels, new tailings treatment infrastructure to meet commitments under the Tailings Management Framework (TMF), ongoing modernization of the company's heavy-haul truck fleet, as well as routine maintenance and risk mitigation projects across all facilities.

The primary focus for both cost management and capital discipline in 2017 will be to continue efforts to sustainably reduce controllable operating costs through elimination of non-critical work and close collaboration with suppliers and business partners. Capital discipline continues to focus on managing investment opportunities, including sustainability priorities, through a robust asset development process and realizing productivity improvements.

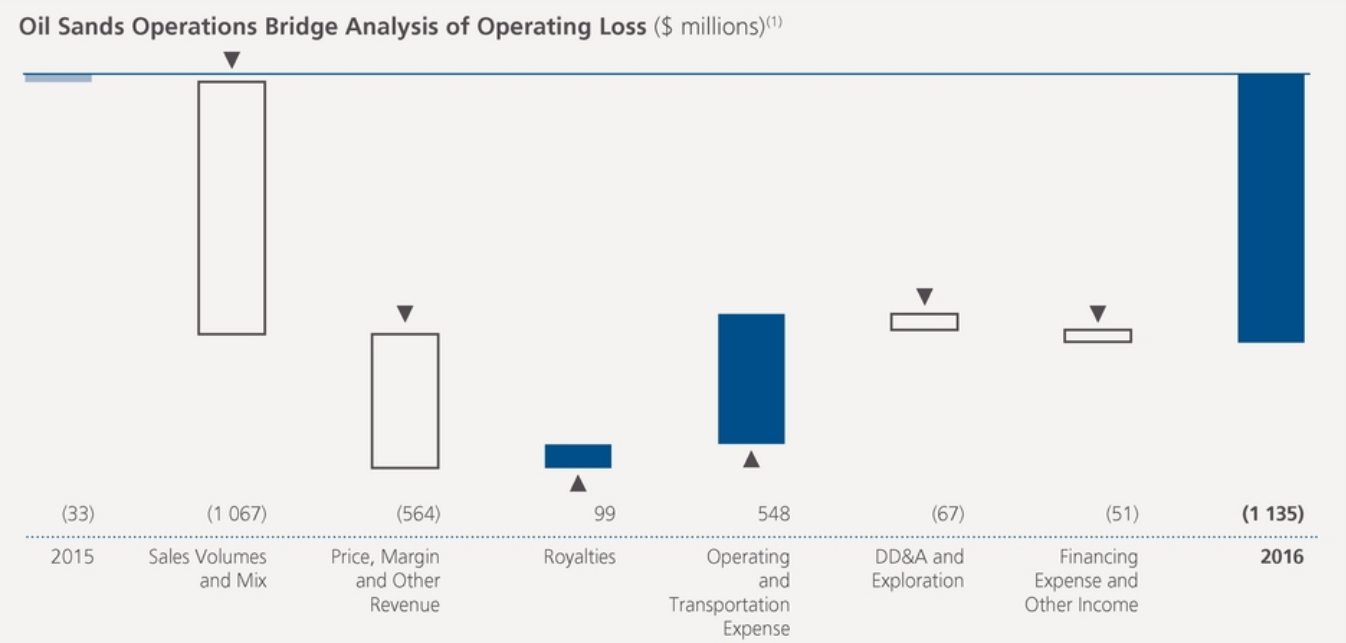
Suncor continues to work closely with the Fort Hills mining project co-owners on construction, commissioning and start-up activities. Suncor is developing the mine using traditional open-pit truck and shovel techniques, and value-added carbon-rejecting extraction technology that will allow the mine to produce a higher quality and lower greenhouse gas (GHG) intensity bitumen product that can be sold directly to the market. After optimization and technical review, the company has increased the nameplate capacity of the Fort Hills project to 194,000 bbls/d.

Financial Highlights

Year ended December 31 ($ millions)	2016	2015	2014
Gross revenues	**9 522**	9 332	14 561
Less: Royalties	**(52)**	(114)	(982)
Operating revenues, net of royalties	**9 470**	9 218	13 579
Net (loss) earnings	**(1 149)**	(856)	1 776
Adjusted for:			
Derecognition and impairments	**40**	386	941
Impact of income tax adjustments on deferred income taxes	**—**	359	54
Operating (loss) earnings[1]	**(1 109)**	(111)	2 771
Oil Sands operations	**(1 135)**	(33)	2 696
Oil Sands ventures	**26**	(78)	75
Funds from operations[2]	**2 669**	2 835	5 400

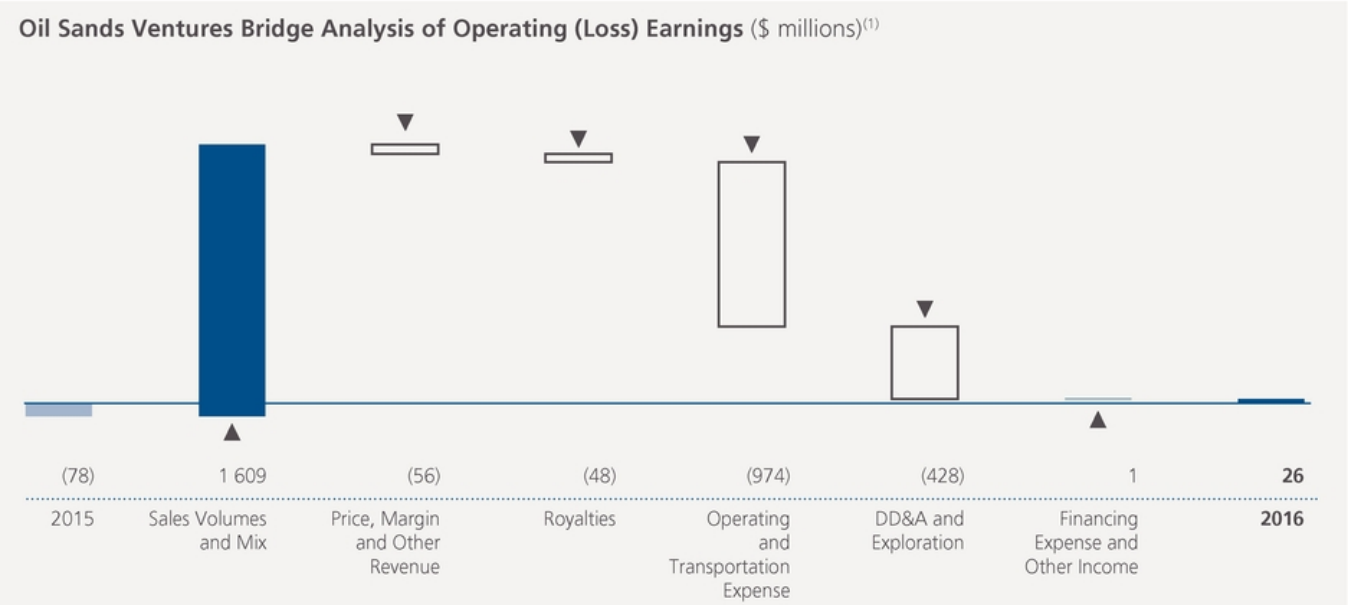
(1) Non-GAAP financial measure. See the Advisories – Non-GAAP Financial Measures section of this MD&A.

(2) Funds from operations was previously referred to as cash flow from operations, with the calculation being unchanged from prior years. Funds from operations is a non-GAAP financial measure. See the Advisories – Non-GAAP Financial Measures section of this MD&A.



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

Operating loss in Oil Sands operations was $1.135 billion in 2016, compared to an operating loss of $33 million in 2015. The increased loss was due to the decrease in sales volumes associated with the production shut-in due to the forest fires in the second quarter of 2016 and lower price realizations attributed to lower crude oil benchmark prices, partially offset by lower operating expenses as a result of the company's cost reduction initiatives, as well as favourable royalties.



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

Operating earnings for Oil Sands ventures were $26 million in 2016, compared to an operating loss of $78 million in 2015. The improvement was primarily due to a higher share of Syncrude sales volumes as a result of working interests acquired in 2016 combined with significantly improved upgrader utilization in the last half of the year, partially offset by additional operating and DD&A expenses associated with the acquired production, the production outage due to the forest fires and lower benchmark crude pricing.

Funds from operations for the Oil Sands segment were $2.669 billion in 2016, compared to $2.835 billion in 2015. The decrease was due to the same cash factors that impacted operating earnings.

Production Volumes(1)

Year ended December 31 (mbbls/d)	**2016**	2015	2014
Upgraded product (SCO)	**258.9**	320.1	289.1
Non-upgraded bitumen	**115.9**	113.5	101.8
Oil Sands operations	**374.8**	433.6	390.9
Oil Sands ventures – Syncrude sweet SCO	**130.1**	29.8	31.0
Total	**504.9**	463.4	421.9

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

Sales Volumes and Mix

Year ended December 31 (mbbls/d)	**2016**	2015	2014
Oil Sands operations sales volumes			
Sweet SCO	**87.3**	107.0	99.7
Diesel	**21.2**	31.3	30.7
Sour SCO	**153.4**	182.5	158.9
Upgraded product (SCO)	**261.9**	320.8	289.3
Non-upgraded bitumen	**117.4**	107.7	101.4
Oil Sands operations	**379.3**	428.5	390.7
Oil Sands ventures	**130.1**	29.8	31.0
Total	**509.4**	458.3	421.7

Oil Sands operations production decreased to 374,800 bbls/d in 2016 from 433,600 bbls/d in 2015, primarily due to the loss of production associated with the forest fires in the Fort McMurray area and a major turnaround of Upgrader 2 in the second quarter, with both 2016 and 2015 impacted by planned maintenance in the third and fourth quarters. Lower SCO production was partially offset by an increase in non-upgraded bitumen, which was a result of debottleneck activities at

Firebag completed in the fourth quarter of 2015 and strong reliability.

Sales volumes for Oil Sands operations decreased to 379,300 bbls/d in 2016, compared to 428,500 bbls/d in 2015, reflecting the same factors that led to the overall decrease in production volumes.

Suncor's share of Syncrude production and sales volumes averaged 130,100 bbls/d in 2016, compared to

29,800 bbls/d in 2015. The increase is due to additional working interests acquired in 2016 combined with significantly improved upgrader reliability, partially offset by the decrease in production associated with the forest fires in the second quarter of 2016.

Bitumen Production from Operations

Year ended December 31	**2016**	2015	2014
Oil Sands Base			
Bitumen production (mbbls/d)	**238.0**	307.3	274.4
Bitumen ore mined (thousands of tonnes/day)	**351.1**	461.3	408.5
Bitumen ore grade quality (bbls/tonne)	**0.68**	0.67	0.67
In Situ bitumen production (mbbls/d)			
Firebag	**180.8**	186.9	172.0
MacKay River	**27.6**	30.7	27.0
Total In Situ production	**208.4**	217.6	199.0
In Situ steam-to-oil ratio			
Firebag	**2.6**	2.6	2.8
MacKay River	**3.2**	2.9	2.9

Bitumen production from Oil Sands Base operations decreased to an average of 238,000 bbls/d in 2016, compared to 307,300 bbls/d in 2015. The decrease was due to the production outage associated with the forest fires in the second quarter of 2016 and an increase in planned maintenance.

In Situ production decreased to 208,400 bbls/d in 2016 from 217,600 bbls/d in 2015. The decrease was driven by the production outage associated with the forest fires in the second quarter of 2016, partially offset by debottleneck activities at Firebag completed in the fourth quarter of 2015, as well as strong reliability.

Firebag's steam-to-oil (SOR) ratio was comparable with the prior year. MacKay River's SOR increased to 3.2 in 2016 from 2.9 in 2015 due to additional steam requirements for a new well pad.

Price Realizations

Year ended December 31 Net of transportation costs, but before royalties ($/bbl)	**2016**	2015	2014
Oil Sands operations			
SCO and diesel	**49.77**	56.45	95.69
Bitumen	**18.12**	25.92	60.56
Crude sales basket (all products)	**39.97**	48.78	86.57
Crude sales basket, relative to WTI	**(17.83)**	(13.72)	(15.63)
Oil Sands ventures			
Syncrude – sweet SCO	**56.38**	59.74	96.06
Syncrude, relative to WTI	**(1.42)**	(2.76)	(6.14)

Price realizations were negatively impacted by the decrease in WTI benchmark prices, partially offset by the weaker Canadian dollar in 2016 and resulted in average price realizations for Oil Sands operations of $39.97/bbl in 2016, compared to $48.78/bbl in 2015.

Suncor's average price realization for Syncrude sales decreased in 2016 to $56.38/bbl, compared to $59.74/bbl in 2015, as the impacts of the decrease in WTI benchmark prices were partially offset by the weaker Canadian dollar in 2016.

Royalties

Royalties were lower in 2016 relative to 2015, primarily due to favourable royalty audit settlements, lower bitumen prices and lower volumes at Oil Sands operations, partially offset by higher Syncrude royalties.

Expenses and Other Factors

Operating expenses for 2016 were higher relative to 2015, primarily due to the company's increased working interest in Syncrude, partially offset by the impact of Suncor's cost reduction initiatives at Oil Sands operations and lower natural gas prices. Although the company's share of absolute costs have increased at Syncrude as a result of the acquisition of additional working interests, operating costs on a per unit basis in 2016 have decreased when compared to 2015 due to increased production combined with cost reduction initiatives made by the operator and lower natural gas prices. See the Cash Operating Costs section below for further details.

Transportation expense was higher in 2016, when compared to 2015, primarily due to the increased sales volumes associated with the increased share of Syncrude production.

DD&A expense for 2016 was higher than 2015, mainly due to a higher share of Syncrude DD&A as a result of additional working interests acquired in 2016 and a larger asset base primarily due to assets commissioned during 2015, including well pads and infill wells.

Cash Operating Costs

Year ended December 31	**2016**	2015	2014
Oil Sands operations cash operating costs[1] reconciliation			
Operating, selling and general expense (OS&G)	**5 777**	5 220	5 940
Syncrude OS&G	**(1 749)**	(471)	(564)
Non-production costs[2]	**(136)**	(97)	(117)
Excess power capacity and other[3]	**(197)**	(245)	(386)
Inventory changes	**(63)**	—	(53)
Oil Sands operations cash operating costs[1] ($ millions)	**3 632**	4 407	4 820
Oil Sands operations cash operating costs[1] ($/bbl)	**26.50**	27.85	33.80
Syncrude cash operating costs[1] reconciliation			
Syncrude OS&G	**1 749**	471	564
Non-production costs[2]	**(31)**	(14)	(9)
Syncrude cash operating costs[1] ($ millions)	**1 718**	457	555
Syncrude cash operating costs[1] ($/bbl)	**35.95**	42.00	49.15

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

(2) Significant non-production costs include, but are not limited to, share-based compensation expense and research expenses.

(3) Excess power capacity and other includes, but is not limited to, the operational revenue impacts of excess power from cogeneration units and the natural gas expense recorded as part of a non-monetary arrangement involving a third-party processor.

Oil Sands operations cash operating costs per barrel averaged $26.50/bbl in 2016, compared to $27.85/bbl in 2015, despite the loss of production associated with the forest fires. The decrease was due to lower operating and maintenance costs as a result of the company's cost reduction initiatives and lower natural gas input costs. Total Oil Sands operations cash operating costs decreased 18% to $3.632 billion from $4.407 billion in the prior year.

In 2016, non-production costs, which are excluded from Oil Sands operations cash operating costs, were higher than the prior year, primarily due to an increase in share-based compensation which was attributed to an increase in the company's share price.

Excess power capacity and other was lower than the prior year due to lower cogeneration power sales as a result of lower power prices.

Inventory changes in 2016 represent a draw of inventory, as compared to no impact in 2015, with the inventory build being offset by a write-down of inventory to fair market value.

Syncrude cash operating costs per barrel decreased to $35.95 in 2016, compared to $42.00 in the previous year despite the impact of the forest fires, as a result of improved reliability combined with cost reduction initiatives made by the operator and lower natural gas prices, partially offset by lower production as a result of the forest fires. Suncor's share of Syncrude cash operating costs increased to $1.718 billion from $464 million in the previous year, primarily due to the additional Syncrude working interests acquired in 2016, partially offset by the previously noted cost reductions. Non-production costs, which are excluded from cash operating costs per barrel, increased over the prior year due to the additional Syncrude working interests acquired in 2016.

Planned Maintenance of Operated Assets

Planned Upgrader 1 maintenance at Oil Sands Base is scheduled to commence at the end of the first quarter of 2017, with completion anticipated in the second quarter of 2017. Additional maintenance events at Upgrader 2 and Upgrader 1 are scheduled for the second quarter of 2017 and the third quarter of 2017, respectively. A planned turnaround is also scheduled for Firebag in the second quarter of 2017. The impact of this maintenance has been reflected in the company's 2017 guidance.

EXPLORATION AND PRODUCTION

2016 Highlights

- E&P delivered another year of reliable, low cost operations in 2016. Reliable production from East Coast Canada and the U.K. helped to maintain comparable funds from operations in 2016, when benchmark crude prices decreased by 17% from 2015.
- E&P Canada production increased to 52,900 boe/d from 47,000 boe/d in the prior year, as a result of new wells being brought online at Hibernia, reservoir optimization and reliability improvements at Terra Nova, and lower planned maintenance than in 2015.
- Hebron project construction continued with the integrated topsides towed out to the deepwater construction site and successfully mated with the gravity-based structure. First oil is expected in late 2017.
- Acquired a 30% participating interest in the Rosebank future development project, located in the U.K. North Sea, which is expected to be complementary to Suncor's existing U.K. portfolio.
- The company sanctioned the non-operated Oda development project in Norway. First oil is expected in 2019.

Strategy and Investment Update

The Exploration and Production segment focuses primarily on low-cost projects that deliver significant returns, cash flow and long-term value. Suncor is currently evaluating exploration and development opportunities off the east coast of Canada, offshore Norway and in the U.K. North Sea to provide diverse and lower cost conventional production.

Construction of the Hebron project continued in 2016, with the integrated topsides being towed out to the deepwater construction site and successfully mated with the gravity-based structure in the fourth quarter. Work will continue in 2017, including tow out and installation at the Hebron field and development drilling. First oil from the project is expected in late 2017.

The Oda field offshore Norway (formerly referred to as the Butch discovery), was sanctioned during the fourth quarter of 2016. Suncor is a 30% non-operating partner in Oda, with the company's share of peak oil production estimated to be 10,500 boe/d. Work on Oda will continue in 2017 and include construction of the subsea production system, with first oil expected in 2019.

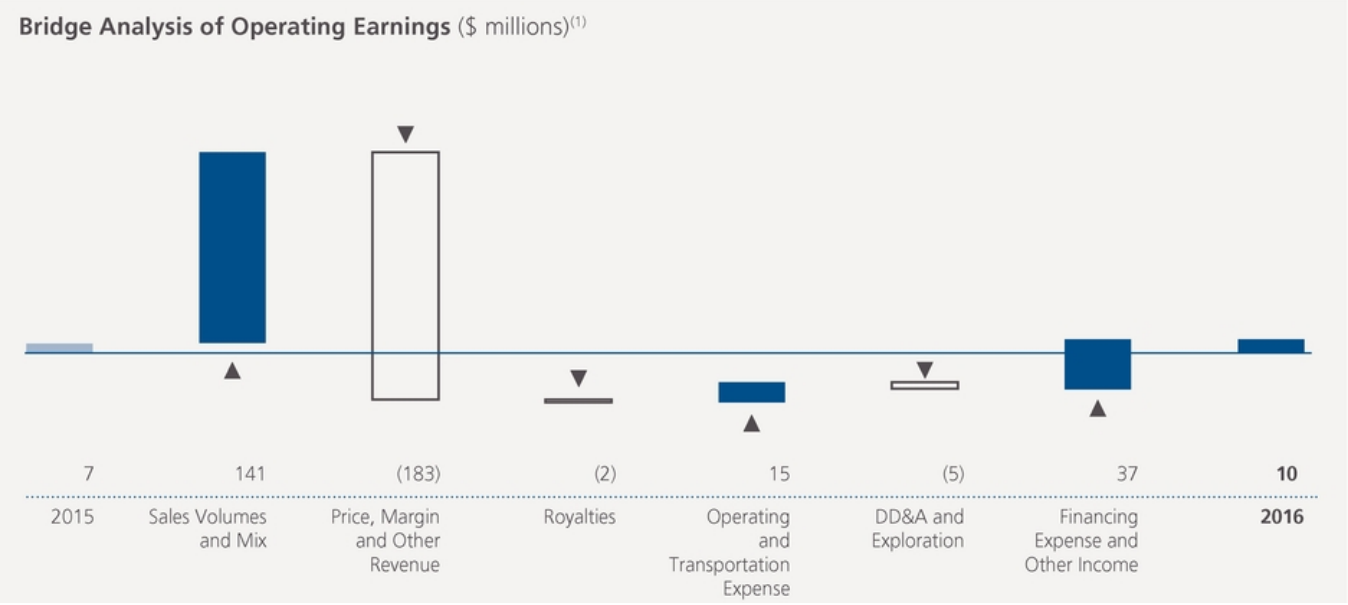
The company also has ongoing field extension projects which leverage existing facilities and infrastructure. The HSEU and South White Rose Extension (SWRX) projects are providing incremental production and extending the productive life of the existing fields. The company also plans on performing drilling activities at Terra Nova in the second half of 2017, continuing into 2018.

Financial Highlights

Year ended December 31 ($ millions)	2016	2015	2014
Gross revenues	**2 444**	2 612	4 715
Less: Royalties	**(213)**	(267)	(672)
Operating revenues, net of royalties	**2 231**	2 345	4 043
Net earnings (loss)	**190**	(758)	653
Adjusted for:			
Impact of income tax rate adjustments on deferred income taxes	**(180)**	(373)	—
Impairments	**—**	1 213	297
Insurance proceeds	**—**	(75)	—
Gain on significant disposals	**—**	—	(61)
Reserves redetermination	**—**	—	(32)
Operating earnings[1]	**10**	7	857
E&P Canada	**(58)**	(14)	502
E&P International	**68**	21	355
Funds from operations[2]	**1 313**	1 386	1 909

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

(2) Funds from operations was previously referred to as cash flow from operations, with the calculation being unchanged from prior years. Funds from operations is a non-GAAP financial measure. See the Advisories – Non-GAAP Financial Measures section of this MD&A.



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

The operating loss in 2016 of $58 million for E&P Canada was larger than the operating loss of $14 million in the prior year, primarily due to increased exploration activity and lower price realizations, partially offset by increased sales volumes.

Operating earnings for E&P International were $68 million in 2016, compared to $21 million in 2015, and were higher primarily due to decreased DD&A expense, a reduced tax rate in the U.K. and lower operating expenses, partially offset by lower crude price realizations.

Funds from operations were $1.313 billion in 2016, compared to $1.386 billion in 2015. The decrease was largely due to a decrease in crude price realizations,

partially offset by increased East Coast Canada production and lower operating costs.

Production Volumes

Year ended December 31	**2016**	2015	2014
E&P Canada			
Terra Nova (mbbls/d)	**12.4**	13.5	17.3
Hibernia (mbbls/d)	**26.8**	18.1	23.1
White Rose (mbbls/d)	**10.9**	12.2	14.6
North America Onshore (mboe/d)	**2.8**	3.2	3.6
	52.9	47.0	58.6
E&P International			
Buzzard (mboe/d)	**46.0**	49.8	47.1
Golden Eagle (mboe/d)	**18.6**	14.8	0.6
Libya (mbbls/d)[(1)]	**0.4**	2.8	6.7
	65.0	67.4	54.4
Total Production (mboe/d)	**117.9**	114.4	113.0
Production Mix (liquids/gas) (%)	**96/4**	96/4	97/3

(1) Effective in 2016, production volumes for Libya are presented on an entitlement basis when there is certainty on the collection of sales revenue.

E&P Canada production averaged 52,900 boe/d in 2016, compared to 47,000 boe/d in 2015.

- Production from Terra Nova averaged 12,400 bbls/d in 2016, compared to 13,500 bbls/d in 2015, with natural declines in the first half of the year being partially offset by reservoir optimization and improved reliability in the second half of the year.
- Production from Hibernia averaged 26,800 bbls/d in 2016, compared to 18,100 bbls/d in 2015, with the increase primarily due to new wells being brought online in 2016. The prior year was also impacted by a five-week planned maintenance program.
- Production from White Rose averaged 10,900 bbls/d in 2016, compared to 12,200 bbls/d in 2015, with the decrease primarily due to natural declines.
- Production from North America Onshore averaged 2,800 boe/d in 2016, compared to 3,200 boe/d in 2015.

E&P International production averaged 65,000 boe/d in 2016, compared to 67,400 boe/d in 2015.

- Production from Buzzard averaged 46,000 boe/d in 2016, compared to 49,800 boe/d in 2015. Production decreased due to the impact of a five-week planned maintenance program in 2016.
- Production from Golden Eagle averaged 18,600 boe/d in 2016, compared to 14,800 boe/d in 2015, as peak production rates were achieved in the second half of 2015 and maintained through 2016.
- Production from Libya averaged 400 bbls/d on an entitlement basis in 2016, compared to 2,800 bbls/d in 2015, which was on a working interest basis. Production in Libya remained substantially shut in during 2016 due to political unrest, with the timing of a return to normal operations remaining uncertain.

Price Realizations

Year ended December 31 Net of transportation costs, but before royalties	**2016**	2015	2014
Exploration and Production			
E&P Canada – Crude oil and natural gas liquids ($/bbl)	**57.37**	62.87	105.98
E&P Canada – Natural gas ($/mcf)	**1.71**	1.78	4.49
E&P International ($/boe)	**52.07**	61.44	104.12
E&P average price ($/boe)	**53.34**	60.53	103.05

Average price realizations for crude oil from E&P Canada and E&P International in 2016 were lower than 2015, consistent with the decrease in benchmark prices for Brent crude in 2016, partially offset by favourable foreign exchange rates.

Expenses and Other Factors

Operating and transportation expenses were lower in 2016, compared to 2015, primarily due to cost reduction initiatives and lower transportation expense in the U.K. due to decreased tariffs.

Exploration expenses increased in 2016, compared to the prior year, due to higher after-tax charges for non-commercial wells.

DD&A expense decreased in 2016, compared to the prior year, primarily due to lower depletion rates at Golden Eagle and White Rose as a result of the impairment charges in the fourth quarter of 2015, partially offset by higher production at Hibernia and an impairment charge associated with the Beta development in Norway.

Planned Maintenance of Operated Assets

A planned three-week maintenance event at Terra Nova has been scheduled to commence in the third quarter of 2017. The impact of this maintenance has been reflected in the company's 2017 guidance.

REFINING AND MARKETING

2016 Highlights

- The Refining and Marketing segment generated $1.890 billion in operating earnings and $2.606 billion of funds from operations [(1)] in 2016.
- Refinery crude throughput remained strong at 428,600 bbls/d, with an average refinery utilization of 93% in 2016.
- Stronger product location and crude differentials, solid operational performance and continued cost management discipline helped to partially offset significantly lower benchmark crack spreads, which declined by approximately 30% in 2016 compared with 2015.
- FIFO gain of $111 million in 2016, compared to a FIFO loss of $286 million in 2015.
- Subsequent to year end, Suncor completed the sale of its Petro-Canada lubricants business for gross proceeds of $1.125 billion.

Strategy and Investment Update

Suncor's downstream operations are a key component of the integrated business model. The Refining and Marketing network serves to maximize Suncor's integrated returns by extending the value chain from oil sands production to the end customer. The company operates its refineries at high levels of utilization to provide reliable offtake and secure pricing for a portion of our oil sands production.

Suncor's Petro-Canada branded-network maintained its position as a leading retailer by market share in major urban areas of Canada and as a bulk supplier of refined crude products through the wholesale channel. Suncor plans to continue to leverage the strong brand to increase non-petroleum revenues through the company's network of convenience stores and car washes.

Suncor also previously operated a lubricants business located in Mississauga, Ontario that manufactures and blends products which were marketed worldwide. During 2016, Suncor entered into an agreement to sell its lubricants business for gross proceeds of $1.125 billion, with the sale closing on February 1, 2017. A long-term arrangement has been completed whereby Suncor will continue to supply the lubricants plant with feedstock from the Montreal refinery. The lubricants business will continue to use the Petro-Canada brand. The lubricants business contributed $133 million in net earnings and $183 million in funds from operations in 2016.

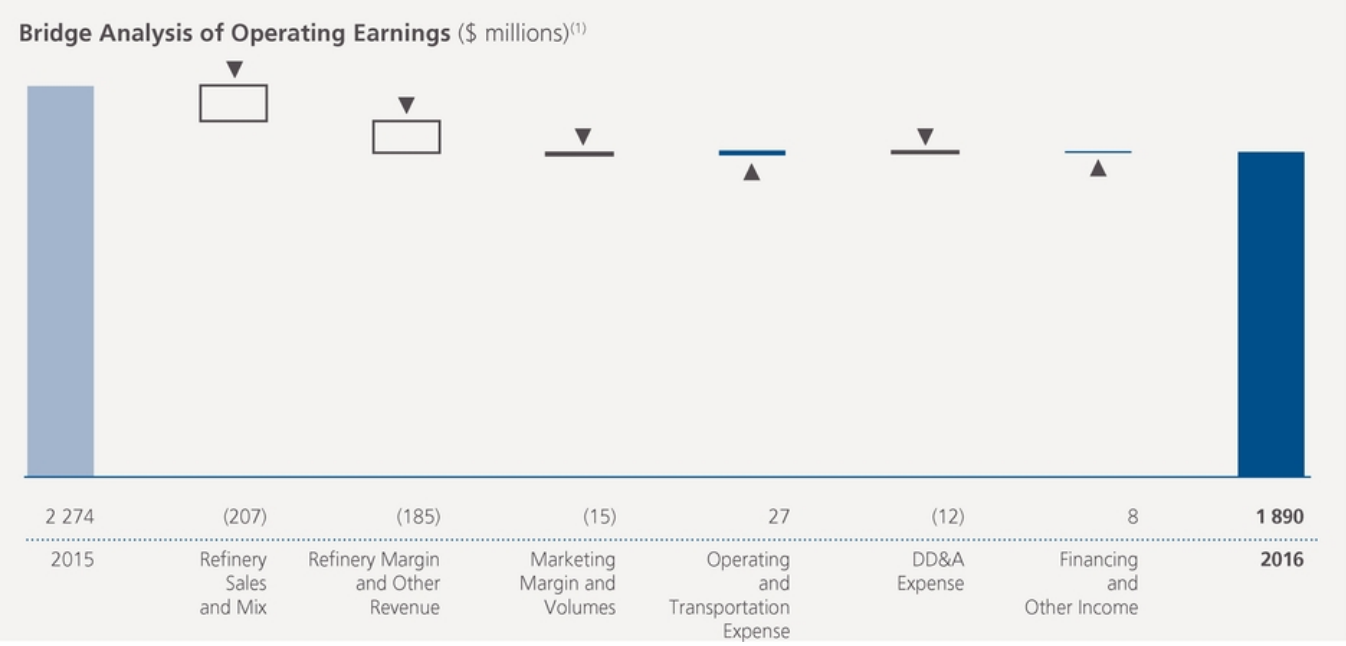
Financial Highlights

Year ended December 31 ($ millions)	**2016**	2015	2014
Operating revenues	**17 567**	19 882	26 683
Net earnings	**1 890**	2 306	1 767
Adjusted for:			
Impact of income tax rate adjustments on deferred taxes	**—**	36	—
Gain on significant disposal	**—**	(68)	—
Operating earnings[(1)]	**1 890**	2 274	1 767
Refining and Product Supply	**1 527**	1 904	1 460
Marketing	**363**	370	307
Funds from operations[(2)]	**2 606**	2 921	2 262

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

(2) Funds from operations was previously referred to as cash flow from operations, with the calculation being unchanged from prior years. Funds from operations is a non-GAAP financial measure. See the Advisories – Non-GAAP Financial Measures section of this MD&A.

(1) Funds from operations was previously referred to as cash flow from operations, with the calculation being unchanged from prior years. Funds from operations is a non-GAAP financial measure. See the Advisories – Non-GAAP Financial Measures section of this MD&A.



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

Refining and Product Supply contributed operating earnings of $1.527 billion in 2016, compared with $1.904 billion in 2015. The decrease was due to an approximate 30% decrease in benchmark crack spreads in 2016 and an unfavourable mix of refined product sales, partially offset by a FIFO gain, compared to a FIFO loss in the prior year, and stronger product location and wider crude differentials.

Marketing operating earnings of $363 million in 2016 were comparable to operating earnings of $370 million in 2015.

Funds from operations were $2.606 billion in 2016, compared to $2.921 billion in 2015, due primarily to the same factors that impacted operating earnings above.

Volumes

Year ended December 31	**2016**	2015	2014
Crude oil processed (mbbls/d)			
Eastern North America	**203.1**	208.1	199.2
Western North America	**225.5**	224.0	228.3
Total	**428.6**	432.1	427.5
Refinery utilization[1][2] (%)			
Eastern North America	**92**	94	90
Western North America	**94**	93	95
Total	**93**	94	93
Refined Product Sales (mbbls/d)			
Gasoline	**244.3**	246.2	243.4
Distillate	**186.1**	198.0	199.7
Other	**91.0**	79.1	88.6
Total	**521.4**	523.3	531.7
Refining gross margin[2] ($/bbl)	**20.30**	24.90	23.80
Refining operating expense[2] ($/bbl)	**5.10**	5.10	6.00

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

(2) Refining gross margin and refining operating expense are non-GAAP financial measures. See the Advisories – Non-GAAP Financial Measures section of this MD&A.

Refinery utilization in Eastern North America averaged 92% in 2016, compared with 94% in 2015. The decrease from the prior year was primarily due to an increase in planned maintenance at both the Sarnia and Montreal refineries.

Refinery utilization in Western North America averaged 94% in 2016, compared to 93% in 2015. The increase from the prior year was primarily due to fewer planned maintenance activities in 2016, compared with 2015, partially offset by lower demand for refined products in Western North America.

Total refinery sales in 2016 were comparable to 2015, with decreased distillate sales associated with weaker demand in Western North America being offset by an increase in other refined products.

Prices and Margins

Refining and Product Supply prices and margins were lower in 2016 compared to 2015.

- Lower benchmark refining crack spreads due to increased levels of North American refined product inventories.
- Stronger refined product location differentials due to improved local supply and demand fundamentals in 2016.
- In 2016, the impact of FIFO inventory accounting, as used by the company, relative to an estimated LIFO basis of accounting, had a positive impact on net earnings of approximately $111 million after-tax, compared to a negative impact of $286 million after-tax in 2015, for a favourable year-over-year impact of $397 million.

Marketing margins in 2016 were comparable to the prior year.

Expenses and Other Factors

Operating expenses were lower in 2016 compared to 2015, primarily due to the impact of the company's cost reduction initiatives combined with lower energy costs, as a result of lower natural gas prices.

Planned Maintenance

The company has a planned maintenance event at the Montreal refinery in the second quarter of 2017. The impact of this maintenance has been reflected in the company's 2017 guidance.

CORPORATE, ENERGY TRADING AND ELIMINATIONS

2016 Highlights

- Completed a common share offering for net proceeds of $2.8 billion to fund the acquisition of Murphy's 5% working interest in Syncrude and to reduce short-term borrowings and a portion of long-term debt acquired as part of the COS acquisition, to provide ongoing balance sheet flexibility.
- Successfully issued $1.0 billion of long-term debt to pay down short-term indebtedness, improving liquidity and balance sheet flexibility.
- Returned cash to shareholders through dividends of $1.877 billion in 2016.
- Completed the sale of Suncor's interest in the Cedar Point wind facility on January 24, 2017.

Strategy and Investment Update

The Energy Trading business supports the company's production by securing market access, optimizing price realizations, managing inventory levels and managing the impacts of external market factors, such as pipeline disruptions or outages at refining customers, while generating trading earnings through established strategies. The Energy Trading business continues to evaluate additional pipeline agreements to support planned production growth.

The company's strategy includes divesting of non-core assets that are not key components of the integrated model. In 2016, Suncor commenced a sale process for certain assets and associated liabilities related to its Renewable Energy business, with an agreement reached for the sale of its interest in the Cedar Point wind facility for gross proceeds of $291 million. The transaction closed on January 24, 2017.

Financial Highlights

Year ended December 31 ($ millions)	2016	2015	2014
Net loss	**(486)**	(2 687)	(1 497)
Adjusted for:			
Unrealized foreign exchange (gain) loss on U.S. dollar denominated debt	**(524)**	1 930	722
Non-cash mark to market gain on interest rate swaps	**(6)**	—	—
Derecognition and impairments	**31**	—	—
Non-cash loss on early payment of long-term debt	**73**	—	—
COS acquisition and related costs	**38**	—	—
Restructuring charges	**—**	57	—
Impact of income tax rate adjustments on deferred income taxes	**—**	(5)	—
Operating (loss) earnings[1]	**(874)**	(705)	(775)
Renewable Energy	**38**	16	3
Energy Trading	**4**	36	66
Corporate	**(864)**	(799)	(850)
Eliminations	**(52)**	42	6
Funds used in operations[2]	**(600)**	(336)	(513)

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

(2) Funds used in operations was previously referred to as cash flow used in operations, with the calculation being unchanged from prior years. Funds used in operations is a non-GAAP financial measure. See the Advisories – Non-GAAP Financial Measures section of this MD&A.

Renewable Energy

Year ended December 31	2016	2015	2014
Power generation marketed (gigawatt hours)[1]	**478**	440	412

(1) Power generated includes curtailed production for which the company was compensated.

Suncor's Renewable Energy assets contributed operating earnings of $38 million in 2016, compared to $16 million in 2015. The increase was primarily due to a recovery of deferred income tax and higher wind production.

Energy Trading

Energy Trading activities contributed operating earnings of $4 million in 2016, compared to $36 million in 2015. The decrease in operating earnings was primarily due to narrower crude location differentials and weaker demand resulting in lower gains on crude trading, partially offset by favourable natural gas trading.

Corporate

Corporate incurred an operating loss of $864 million in 2016, compared with $799 million in 2015. The increase in the operating loss was primarily a result of higher share-based compensation expense, additional interest expense associated with the debt acquired as part of the COS acquisition in 2016, and unfavourable operational foreign exchange movements, partially offset by cost reduction initiatives and higher capitalized interest. Suncor capitalized $596 million of its borrowing costs in 2016 as part of the cost of major development assets and construction projects in progress, compared to $447 million in the prior year. The increase was driven by higher accumulated capital project balances for Fort Hills and Hebron.

Eliminations

Eliminations reflect the elimination or realization of profit on crude oil sales from Oil Sands and East Coast Canada to Refining and Marketing. Consolidated profits are only realized when the company sells the products produced from intersegment purchases of crude feedstock to third parties. In 2016, the company eliminated $52 million of after-tax intersegment profit, compared to a $42 million realization of after-tax intersegment profit in the prior year. The elimination of profit in 2016 is due to an increased volume of intercompany crude held at the refineries.

5. FOURTH QUARTER 2016 ANALYSIS

Financial and Operational Highlights

Three months ended December 31 ($ millions, except as noted)	2016	2015
Net earnings (loss)		
Oil Sands	**276**	(616)
Exploration and Production	**54**	(1 263)
Refining and Marketing	**524**	506
Corporate, Energy Trading and Eliminations	**(323)**	(634)
Total	**531**	(2 007)
Operating earnings (loss)[(1)]		
Oil Sands	**316**	(230)
Exploration and Production	**54**	(50)
Refining and Marketing	**524**	506
Corporate, Energy Trading and Eliminations	**(258)**	(252)
Total	**636**	(26)
Funds from (used in) operations[(1)(2)]		
Oil Sands	**1 372**	467
Exploration and Production	**385**	257
Refining and Marketing	**722**	605
Corporate, Energy Trading and Eliminations	**(114)**	(35)
Total	**2 365**	1 294
Production volumes (mboe/d)		
Oil Sands	**620.4**	470.6
Exploration and Production	**118.1**	112.3
Total	**738.5**	582.9

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

(2) Funds from (used in) operations was previously referred to as cash flow from (used in) operations, with the calculation being unchanged from prior years. Funds from (used in) operations is a non-GAAP financial measure. See the Advisories – Non-GAAP Financial Measures section of this MD&A.

Net Earnings

Suncor's consolidated net earnings for the fourth quarter of 2016 were $531 million, compared with a net loss of $2.007 billion for the prior year quarter. Net earnings were primarily affected by the same factors that influenced operating earnings described in the segmented analysis below. Other items affecting net earnings over these periods included:

- The after-tax unrealized foreign exchange loss on the revaluation of U.S. dollar denominated debt was $222 million for the fourth quarter of 2016, compared to $382 million for the fourth quarter of 2015.
- The company recognized a non-cash after-tax mark to market gain on forward interest rate derivatives in the Corporate segment of $188 million in the fourth quarter of 2016 due to an increase in long-term interest rates.
- During the fourth quarter of 2016, the company recorded after-tax derecognition charges of $40 million on certain upgrading and logistics assets in the Oil Sands segment, as well as $31 million in the Corporate segment relating to an initial investment in an undeveloped pipeline and on certain renewable energy development assets as a result of the uncertainty of future benefits from these assets.
- In the fourth quarter of 2015, the company recorded after-tax impairment charges against property, plant and equipment and exploration and evaluation assets of $359 million on White Rose, $331 million on Golden Eagle and $54 million on Terra Nova, as a result of impacts of a decline in the crude oil price forecast. In addition, impairment charges of $290 million were recorded against the Joslyn mining project and $54 million on the Ballicatters well, due to uncertainty on the timing and likelihood of development plans, and $96 million in Oil Sands following a review of certain assets that no longer fit with Suncor's growth strategies and which could not be repurposed or otherwise deployed.
- In the fourth quarter of 2015, as a result of shut-in production due to the continued closure of certain Libyan export terminals, escalating political unrest, and increased uncertainty with respect to the company's return to normal operations in the country, the company recorded an after-tax impairment charge of $415 million against property, plant and equipment and exploration and evaluation assets.

Funds from Operations (previously referred to as cash flow from operations)

Consolidated funds from operations was $2.365 billion for the fourth quarter of 2016 compared to $1.294 billion for the prior year quarter. Funds from operations were impacted by the same cash factors that affected operating earnings in the segmented analysis described below.

Segmented Analysis

Oil Sands

Oil Sands operating earnings for the fourth quarter of 2016 were $316 million, compared to an operating loss of $230 million in the prior year quarter. The increase was primarily due to higher crude price realizations, consistent with increased benchmark pricing, lower operating and maintenance expenses attributable to the company's cost reduction initiatives, and a higher share of Syncrude production as a result of additional working interests acquired in 2016, partially offset by increased DD&A associated with the Syncrude acquisitions and a larger asset base at Oil Sands operations, as well as higher natural gas prices.

Production volumes for Oil Sands operations were 433,400 bbls/d in the fourth quarter of 2016, compared to 439,700 bbls/d in the prior year quarter, with the decrease due to an increase in unplanned maintenance in the fourth quarter of 2016.

Suncor's share of Syncrude production increased to 187,000 bbls/d in the fourth quarter of 2016, compared to 30,900 bbls/d in the prior year quarter. The increase was due to additional working interests acquired in 2016 combined with improved upgrader reliability. Syncrude upgrader utilization was 102% of nameplate capacity in the quarter, compared to 73% in the prior year quarter.

Exploration and Production

Exploration and Production operating earnings were $54 million in the fourth quarter of 2016, compared to an operating loss of $50 million in the fourth quarter of 2015. Operating earnings increased primarily due to higher crude price realizations, higher production, lower operating expenses and lower DD&A expense, partially offset by higher royalties and exploration expenses.

Production volumes were 118,100 boe/d in the fourth quarter of 2016, compared to 112,300 boe/d in the fourth quarter of 2015. The increase was primarily due to higher production at Hibernia, with new wells being brought online in 2016, as well as higher production at Terra Nova due to reservoir optimization and improved reliability, partially offset by planned maintenance at Buzzard.

Refining and Marketing

Refining and Marketing operating earnings were $524 million in the fourth quarter of 2016, compared to operating earnings of $506 million for the fourth quarter of 2015. The increase in the fourth quarter of 2016 was primarily due to a FIFO gain of $114 million compared to a FIFO loss of $77 million in the prior period quarter. Lower benchmark refining crack spreads and location differentials in the fourth quarter of 2016 were partially offset by a higher value product mix and favourable crude price differentials.

Refinery crude throughput of 93% in the fourth quarter of 2016 was consistent with the prior year period.

Corporate, Energy Trading and Eliminations

The operating loss for Corporate, Energy Trading and Eliminations in the fourth quarter of 2016 was $258 million, compared to $252 million in the fourth quarter of 2015. The increase was due primarily to higher share-based compensation expense, unfavourable operational foreign exchange, additional interest expense associated with the debt acquired as part of the COS acquisition in early 2016, and higher intersegment profit eliminations. These factors were partially offset by higher Energy Trading operating earnings due to wider crude location differentials, improved market conditions and favourable natural gas trading, an income tax benefit associated with the sale of the company's interest in the Cedar Point wind facility, higher wind production and higher capitalized interest.

6. QUARTERLY FINANCIAL DATA

Financial Summary

Three months ended ($ millions, unless otherwise noted)	**Dec 31 2016**	Sept 30 2016	June 30 2016	Mar 31 2016	Dec 31 2015	Sept 30 2015	June 30 2015	Mar 31 2015
Total production (mboe/d)								
Oil Sands	**620.4**	617.5	213.1	565.8	470.6	458.4	448.7	475.6
Exploration and Production	**118.1**	110.6	117.6	125.6	112.3	107.7	111.2	126.8
	738.5	728.1	330.7	691.4	582.9	566.1	559.9	602.4
Revenues and other income								
Operating revenues, net of royalties	**7 840**	7 409	5 914	5 644	6 499	7 485	8 095	7 129
Other income	**301**	(15)	(58)	(67)	94	72	49	257
	8 141	7 394	5 856	5 577	6 593	7 557	8 144	7 386
Net earnings (loss)	**531**	392	(735)	257	(2 007)	(376)	729	(341)
per common share – basic (dollars)	**0.32**	0.24	(0.46)	0.17	(1.38)	(0.26)	0.50	(0.24)
per common share – diluted (dollars)	**0.32**	0.24	(0.46)	0.17	(1.38)	(0.26)	0.50	(0.24)
Operating earnings (loss)[1]	**636**	346	(565)	(500)	(26)	410	906	175
per common share – basic[1] (dollars)	**0.38**	0.21	(0.36)	(0.33)	(0.02)	0.28	0.63	0.12
Funds from operations[1][2]	**2 365**	2 025	916	682	1 294	1 882	2 155	1 475
per common share – basic[2] (dollars)	**1.42**	1.22	0.58	0.45	0.90	1.30	1.49	1.02
Cash flow provided by operating activities	**2 791**	1 979	862	48	1 443	2 771	1 794	876
per common share – basic (dollars)	**1.68**	1.19	0.54	0.03	1.00	1.92	1.24	0.61
ROCE[1] (%) for the twelve months ended	**0.5**	(4.6)	(4.9)	(2.2)	0.6	5.1	7.2	5.8
After-tax unrealized foreign exchange (loss) gain on U.S. dollar denominated debt	**(222)**	(112)	(27)	885	(382)	(786)	178	(940)
Common share information (dollars)								
Dividend per common share	**0.29**	0.29	0.29	0.29	0.29	0.29	0.28	0.28
Share price at the end of trading								
Toronto Stock Exchange (Cdn$)	**43.90**	36.42	35.84	36.17	35.72	35.69	34.40	37.01
New York Stock Exchange (US$)	**32.69**	27.78	27.73	27.81	25.80	26.72	27.52	29.25

(1) Non-GAAP financial measures. See the Advisories – Non-GAAP Financial Measures section of this MD&A. ROCE excludes capitalized costs related to major projects in progress. Operating earnings (loss) for each quarter are defined in the Non-GAAP Financial Measures Advisory section and reconciled to GAAP measures in the Consolidated Financial Information and Segment Results and Analysis sections of each quarterly Report to Shareholders issued by Suncor (Quarterly Reports) in respect of the relevant quarter. Funds from operations (previously referred to as cash flow from operations) and ROCE for each quarter are defined and reconciled to GAAP measures in the Non-GAAP Financial Measures Advisory section of each Quarterly Report issued by Suncor in respect of the relevant quarter.

(2) Funds from operations was previously referred to as cash flow from operations, with the calculation being unchanged from prior years. Funds from operations is a non-GAAP financial measure. See the Advisories – Non-GAAP Financial Measures Advisory section of this MD&A.

Business Environment

Three months ended (average for the period ended, except as noted)		**Dec 31 2016**	Sept 30 2016	June 30 2016	Mar 31 2016	Dec 31 2015	Sept 30 2015	June 30 2015	Mar 31 2015
WTI crude oil at Cushing	US$/bbl	**49.35**	44.95	45.60	33.50	42.15	46.45	57.95	48.65
Dated Brent crude	US$/bbl	**49.50**	45.85	45.60	33.90	43.70	50.30	61.95	53.85
Dated Brent/Maya FOB price differential	US$/bbl	**6.70**	6.80	7.65	8.95	10.35	8.50	8.15	11.05
MSW at Edmonton	Cdn$/bbl	**62.00**	55.10	55.80	34.50	53.55	56.55	68.05	52.25
WCS at Hardisty	US$/bbl	**35.00**	31.45	32.30	19.30	27.70	33.25	46.35	33.90
Light/heavy crude oil differential for WTI at Cushing less WCS at Hardisty	US$/bbl	**14.35**	13.50	13.30	14.25	14.50	13.20	11.60	14.75
Condensate at Edmonton	US$/bbl	**48.35**	43.05	44.10	34.45	41.65	44.20	57.95	45.60
Natural gas (Alberta spot) at AECO	Cdn$/mcf	**3.10**	2.30	1.40	1.85	2.45	2.90	2.55	2.75
Alberta Power Pool Price	Cdn$/MWh	**21.95**	17.90	14.90	18.10	21.20	26.05	57.25	29.15
New York Harbor 3-2-1 crack (1)	US$/bbl	**14.35**	14.00	16.10	11.75	13.60	22.25	23.85	19.20
Chicago 3-2-1 crack (1)	US$/bbl	**10.55**	14.15	16.65	9.10	13.90	23.95	20.30	16.00
Portland 3-2-1 crack (1)	US$/bbl	**14.95**	18.75	19.30	13.00	17.90	28.75	32.55	21.50
Gulf Coast 3-2-1 crack (1)	US$/bbl	**13.15**	14.50	14.85	11.05	11.05	21.55	22.90	18.00
Exchange rate	US$/Cdn$	**0.75**	0.77	0.78	0.73	0.75	0.76	0.81	0.81
Exchange rate (end of period)	US$/Cdn$	**0.74**	0.76	0.77	0.77	0.72	0.75	0.80	0.79

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

Significant or Unusual Items Impacting Net Earnings

Trends in Suncor's quarterly earnings and funds from operations [(1)] are driven primarily by production volumes, which can be significantly impacted by major maintenance events such as the planned upgrader maintenance that occurred in 2016, and unplanned outages like those resulting from the Fort McMurray forest fires in the second quarter of 2016.

Trends in Suncor's quarterly earnings and funds from operations [(1)] are also affected by changes in commodity prices, price differentials, refining crack spreads and foreign exchange rates, as described in the Financial Information section of this MD&A.

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

- The after-tax unrealized foreign exchange impact on the revaluation of U.S. dollar denominated debt was a loss of $222 million for the fourth quarter of 2016 and a gain of $524 million for the year; the after-tax unrealized foreign exchange loss on the revaluation of U.S. dollar denominated debt was $382 million for the fourth quarter of 2015 and $1.930 billion for the prior year.

- The company recognized a non-cash after-tax mark to market gain on forward interest rate derivatives in the Corporate segment of $188 million in the fourth quarter of 2016 and $6 million for the year due to an increase in long-term interest rates.

- During the fourth quarter of 2016, the company recorded after-tax derecognition charges of $40 million on certain upgrading and logistics assets in the Oil Sands segment, as well as $31 million in the Corporate segment relating to an initial investment in an undeveloped pipeline and on certain renewable energy development assets as a result of the uncertainty of future benefits from these assets.

- In the third quarter of 2016, 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 50% to 40%, effective January 1, 2016. The company revalued its deferred income tax balances, resulting in a deferred income tax recovery of $180 million in the E&P segment.

- In the second quarter of 2016, the company incurred a non-cash after-tax charge of $73 million in the Corporate segment for early payment of long-term debt acquired as part of the COS acquisition.

- In the first quarter of 2016, the company incurred $38 million in after-tax charges associated with the acquisition and integration of COS in the Corporate segment.

- In the fourth quarter of 2015, the company recorded after-tax impairment charges against property, plant and equipment and exploration and evaluation assets of $359 million on White Rose, $331 million on Golden Eagle and $54 million on Terra Nova as a result of impacts of a decline in the crude oil price forecast. In addition, impairment charges of $290 million were recorded on the company's interest in the Joslyn mining project and $54 million on the Ballicatters well, due to uncertainty in the timing and likelihood of development plans, and $96 million in Oil Sands following a review of certain assets that no longer fit with Suncor's growth strategies and which could not be repurposed or otherwise deployed.

- In the fourth quarter of 2015, as a result of shut-in production due to the continued closure of certain Libyan export terminals, escalating political unrest, and increased uncertainty with respect to the company's return to normal operations in the country, the company recorded an after-tax impairment charge of $415 million against property, plant and equipment and exploration and evaluation assets.

- In the second quarter of 2015, the company recorded an after-tax gain of $68 million on the disposal of the company's share of certain assets and liabilities of Pioneer Energy in the R&M segment.

- In the second quarter of 2015, the company recorded a $423 million deferred income tax charge related to a 2% increase in the Alberta corporate income tax rate.

- In 2015, the company recorded a $406 million deferred income tax recovery in the E&P segment related to a reduction in the U.K. tax rate from 62% to 50%.

- In the first quarter of 2015, the company recorded after-tax insurance proceeds of $75 million related to a claim on the Terra Nova asset in the E&P segment.

- In the first quarter of 2015, the company recorded after-tax restructuring charges of $57 million related to cost reduction initiatives in the Corporate segment.

(1) Funds from operations was previously referred to as cash flow from operations, with the calculation being unchanged from prior years. Funds from operations is a non-GAAP financial measure. See the Advisories – Non-GAAP Financial Measures section of this MD&A.

7. CAPITAL INVESTMENT UPDATE

Capital and Exploration Expenditures by Segment

Year ended December 31 ($ millions)	**2016**	2015	2014
Oil Sands	**4 724**	4 181	3 826
Exploration and Production	**1 139**	1 459	1 819
Refining and Marketing	**685**	821	1 024
Corporate, Energy Trading and Eliminations	**34**	206	292
Total	**6 582**	6 667	6 961
Less: capitalized interest on debt	**(596)**	(447)	(431)
	5 986	6 220	6 530

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

Year ended December 31, 2016 ($ millions)	Sustaining	Growth	**Total**
Oil Sands Base	*1 128*	*418*	***1 546***
In Situ	*110*	*21*	***131***
Oil Sands Ventures	*314*	*2 300*	***2 614***
Oil Sands	1 552	2 739	**4 291**
Exploration and Production	12	969	**981**
Refining and Marketing	680	3	**683**
Corporate, Energy Trading and Eliminations	31	—	**31**
	2 275	3 711	**5 986**

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

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

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

In 2016, Suncor spent $5.986 billion on property, plant and equipment and exploration activities, and capitalized $596 million of interest on debt towards major development assets and construction projects. Activity in 2016 included the following:

Oil Sands Base

Oil Sands Base capital expenditures were $1.546 billion, of which $1.128 billion was directed towards sustaining activities. The focus in 2016 was on ensuring continued safe, reliable and efficient operations, and progress was made on key reliability, safety and environmental performance projects. Sustaining capital expenditures were primarily related to planned maintenance in the spring and fall of 2016 and a number of reliability and sustainment projects across the operations.

Oil Sands Base growth capital of $418 million was primarily attributed to construction of the ETF development, which will support market access for Fort Hills bitumen.

In Situ

In Situ capital expenditures were $131 million, of which $110 million was directed towards sustaining capital expenditures. Sustaining capital in 2016 was focused on the ongoing design and construction of well pads that are expected to maintain existing production levels at Firebag and MacKay River in future years as production from existing well pads decline.

Growth capital of $21 million in 2016 was related to development of emerging properties and new technologies, as well as completion of debottleneck activities in the early part of the year.

Oil Sands Ventures

Oil Sands ventures growth capital expenditures of $2.614 billion in 2016 were primarily related to the Fort Hills mining project. The Fort Hills project was more than 76% complete at the end of 2016, with the remaining work to be based at site near Fort McMurray, Alberta. Activities in the year included completion of the secondary extraction and utilities module programs, concluding all significant module program work. Construction in secondary extraction and utilities has achieved peak activity and continues to focus on productivity and achieving critical milestones.

The company has assessed the impact of the construction delay due to the forest fires in the second quarter of 2016, and other construction changes associated with the complexity and scale of secondary extraction detailed design development, and now estimates the overall cost of the Fort Hills' project to be between $16.5 and $17.0 billion. Suncor's share of Fort Hills' remaining project capital is between $1.6 and $1.8 billion. The majority of the spend will occur in 2017 and will be completed within Suncor's existing capital guidance range. In addition, the company has increased the nameplate capacity from 180,000 bbls/d to 194,000 bbls/d after optimization and technical review. With these changes, Suncor's total capital intensity is expected to remain consistent with the original sanction estimate of $84,000 per flowing barrel of bitumen. First oil continues to remain on track for late 2017.

Sustaining capital of $314 million in 2016 included development of early-works sustaining activities at Fort Hills that will support the execution of the mine and tailings plan following the commencement of production. Also included was an increased share of Syncrude sustaining capital in 2016, which was primarily focused on key reliability, safety and environmental projects.

Exploration and Production

Exploration and Production capital and exploration expenditures were $981 million in 2016, of which $969 million was directed towards growth and exploration.

Growth spending included $530 million for Hebron, as construction of the project continued throughout 2016. The topside module was completed and towed out to the deepwater construction site and successfully mated with the gravity-based structure in 2016. First oil from the project is expected in late 2017.

Growth capital at E&P also included development drilling at Hibernia, White Rose and Golden Eagle, as well as two exploration wells at the Shelburne Basin off the east coast of Canada, with the costs subsequently charged to exploration expense in the year.

Refining and Marketing

Refining and Marketing capital expenditures were $683 million in 2016, of which $680 million was directed to sustaining activities focused on planned maintenance events at the company's refineries and in its retail business on the ongoing sustainment of operations, as well as completion of enhancements to an existing pipeline to connect the Commerce City refinery with crude supply.

Significant Growth Projects Update(1)

At December 31, 2016	Working Interest (%)	Description	Cost Estimate ($ billions)	Project Spend to Date ($ billions)	Expected First Oil Date(2)
Operated					
Fort Hills(3)	50.80	98.6 mbbls/d	8.1 – 8.3(5)	6.5	Q4 2017
Non-operated(4)					
Hebron	21.03	31.6 mboe/d	2.8 (+/-10%)	2.2	Q4 2017

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

(2) Expenditure to complete the project may extend beyond the first oil date.

(3) The project cost estimate has been updated to reflect increased cost estimates and the estimated gross plant capacity has been increased to 194,000 bbls/d after optimization and technical review. Cost Estimate and Project Spend to Date figures reflect the company's share of overall project cost and exclude capitalized interest.

(4) Cost and first oil estimates are provided by the operator and reflect post-sanction estimates and expenditures. Project Spend to Date includes the reimbursement of previously incurred costs following the reset of Suncor's working interest in the project to 21.034% from 22.729%, effective January 1, 2016.

(5) The capital range includes approximately $180 million related to the impact of foreign exchange due to weakness in the Canadian dollar.

The table above summarizes major growth projects that have been sanctioned for development by the company. Other potential material growth projects have not yet received a final investment decision by the company or its Board of Directors.

The Fort Hills mining project will be developed using traditional open-pit truck and shovel techniques, and solvent-based extraction technology that will allow the mine to produce bitumen product that is sold directly to market. The project is scheduled to produce first oil late in the fourth quarter of 2017 and achieve over 90% of its planned gross production capacity of 194,000 bbls/d within twelve months. Project activities in 2017 are expected to focus on completion of the extraction facilities, mining, ore processing, site infrastructure, and tailings areas.

The co-owners for the Hebron project sanctioned development on December 31, 2012. The Hebron field includes a gravity-based structure design supporting an expected gross oil production rate of 150,000 bbls/d. Project activity in 2017 is expected to focus on towing the gravity-based structure to its final location, development drilling and readying the facility for first oil.

Other Capital Projects

Suncor also anticipates 2017 capital expenditures to be directed to the following projects and initiatives:

Oil Sands Operations

For 2017, plans for sustaining capital continue to focus on planned maintenance, which includes events at Upgrader 1, Upgrader 2 and Firebag. Additional sustaining capital will be directed at maintaining production capacity at existing facilities, primarily related to new well pads for In Situ assets to offset natural production declines, new tailings treatment infrastructure to meet commitments under TMF, ongoing modernization of the company's heavy-haul truck fleet, as well as routine maintenance and risk mitigation projects across all facilities.

Growth capital will continue to focus on the ETF development, which will support market access for Fort Hills' bitumen.

Oil Sands Ventures

Sustaining capital expenditures in 2017 for Syncrude are expected to focus on planned maintenance, and maintaining production capacity.

Sustaining capital expenditures in 2017 for Fort Hills will continue to develop early-works sustaining activities that will support the execution of the mine and tailings plan following the commencement of production.

Exploration and Production

In addition to the Hebron capital expenditure noted above, growth capital will include development drilling at White Rose, Hibernia and Terra Nova within E&P Canada, as well as spending for the Oda and Rosebank development projects within E&P International.

Refining and Marketing

The company expects that sustaining capital will focus on planned maintenance events and routine asset replacement.

8. FINANCIAL CONDITION AND LIQUIDITY

Liquidity and Capital Resources

At December 31 ($ millions, except as noted)	2016	2015	2014
Net cash from (used in)			
Operating activities	**5 680**	6 884	8 936
Investing activities	**(7 507)**	(6 771)	(6 863)
Financing activities	**869**	(1 854)	(1 872)
Foreign exchange (loss) gain on cash and cash equivalents	**(75)**	295	92
(Decrease) increase in cash and cash equivalents	**(1 033)**	(1 446)	293
Cash and Cash equivalents, end of year	**3 016**	4 049	5 495
Return on Capital Employed (%)[1]			
Excluding major projects in progress	**0.5**	0.6	8.6
Including major projects in progress	**0.4**	0.5	7.5
Net debt to funds from operations[2] (times)	**2.4**	1.7	0.9
Interest coverage on long-term debt (times)			
Earnings basis[3]	**0.5**	(1.8)	6.6
Funds from operations basis[2][4]	**6.5**	9.3	15.5

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

(2) Funds from operations was previously referred to as cash flow from operations, with the calculation being unchanged from prior years. Funds from operations and metrics that use funds from operations are non-GAAP financial measures. See the Advisories – Non-GAAP Financial Measures section of this MD&A.

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

(4) Funds from operations plus current income taxes and interest expense, divided by the sum of interest expense and capitalized interest on debt.

Cash Flow provided by Operating Activities

Cash flow provided by operating activities was $5.680 billion in 2016 compared to $6.884 billion in 2015. The decrease was primarily due to lower upstream price realizations in the first nine months of 2016, consistent with the decline in benchmark crude prices, the impact of shut-in production associated with the forest fires in the Fort McMurray area in the second quarter of 2016, and weaker benchmark crack spreads. An increase in non-cash working capital, as compared to a decrease in non-cash working capital in 2015, further reduced cash flow provided by operating activities. These factors were partially offset by a FIFO gain in downstream operations, when compared to a FIFO loss in the prior year, lower operating costs across the company's operations, a higher share of Syncrude production, which was a result of the acquisition of additional working interests in 2016 combined with significantly improved upgrader reliability in the second half of the year, and higher refined product location differentials.

Cash Flow used in Investment Activities

Cash flow used in investing activities was $7.507 billion in 2016 compared to $6.771 billion in 2015. The increase was primarily due to the acquisition of Murphy's 5% ownership interest in Syncrude and an increase in non-cash investing working capital, partially offset by cash acquired from COS and lower capital expenditures.

Cash Flow provided by Financing Activities

Cash flow provided by financing activities was $869 million in 2016 compared to a cash usage of $1.854 billion in 2015. The increase was primarily due to the issuance of common shares and long-term debt in 2016, partially offset by the early repayment of long-term debt that was acquired as part of the COS acquisition and an increase in dividends paid on common shares.

Capital Resources

Suncor's capital resources consist primarily of cash flow provided by operating activities, cash and cash equivalents, available lines of credit and the realized proceeds from divestiture of non-core assets. Suncor's management believes the company will have the capital resources to fund its planned 2017 capital spending program of $4.8 to $5.2 billion and to meet current and future working capital requirements through cash balances and cash equivalents, cash flow provided by operating activities, available

committed credit facilities, issuing commercial paper and, if needed, divesting of non-core assets and accessing capital markets. The company's cash flow provided by operating activities depends on a number of factors, including commodity prices, production and sales volumes, refining and marketing margins, operating expenses, taxes, royalties and foreign exchange rates.

The company has invested excess cash in short-term financial instruments that are presented as cash and cash equivalents. The objectives of the company's short-term investment portfolio are to ensure the preservation of capital, maintain adequate liquidity to meet Suncor's cash flow requirements and deliver competitive returns derived from the quality and diversification of investments within acceptable risk parameters. The maximum weighted average term to maturity of the short-term investment portfolio is not expected to exceed six months, and all investments will be with counterparties with investment grade debt ratings.

Available Sources of Liquidity

Cash and Cash Equivalents

Included in cash and cash equivalents of $3.016 billion at December 31, 2016 are short-term investments with weighted average terms to maturity of approximately ten days. In 2016, the company earned approximately $24 million of interest income on this portfolio.

Financing Activities

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

Suncor's interest on debt (before capitalized interest) in 2016 was $1.012 billion, an increase from $870 million in 2015 primarily due to the acquisition of COS debt in early 2016 and the weakening of the Canadian dollar.

Available lines of credit at December 31, 2016 increased to $7.467 billion, compared to $7.034 billion at December 31, 2015, primarily as a result of credit facilities added through the acquisition of COS and reduced letters of credit, partially offset by increased short-term borrowings and foreign exchange impacts on available credit facilities.

Subsequent to the end of 2016, the company cancelled a $950 million credit facility that was acquired through the acquisition of COS, reducing available lines of credit to $6.5 billion. The credit facility is no longer required for liquidity purposes and the cancellation will reduce future financing expense.

A summary of total and unutilized credit facilities at December 31, 2016 is as follows:

($ millions)	2016
Fully revolving and expires in 2019	7 685
Fully revolving and expires in 2018	1 750
Fully revolving and expires in 2017 (1)	950
Can be terminated at any time at the option of the lenders	164
Total credit facilities	10 549
Credit facilities supporting outstanding commercial paper	(1 273)
Credit facilities supporting standby letters of credit	(1 139)
Total unutilized credit facilities (2)	8 137

(1) Cancelled in the first quarter of 2017.

(2) Available credit facilities for general purposes were $7.467 billion at December 31, 2016 (December 31, 2015 – $7.034 billion).

Total Debt to Total Debt Plus Shareholders' Equity

Suncor is subject to financial and operating covenants related to its bank debt and public market debt. Failure to meet the terms of one or more of these covenants may constitute an Event of Default as defined in the respective debt agreements, potentially resulting in accelerated repayment of one or more of the debt obligations. The company is in compliance with its financial covenant that requires total debt to not exceed 65% of its total debt plus shareholders' equity. At December 31, 2016, total debt to total debt plus shareholders' equity was 28.1% (December 31, 2015 – 28.2%). The company is currently in compliance with all operating covenants as at December 31, 2016.

At December 31 ($ millions, except as noted)	2016	2015
Short-term debt	**1 273**	747
Current portion of long-term debt	**54**	70
Long-term debt	**16 103**	14 486
Total debt	**17 430**	15 303
Less: Cash and cash equivalents	**3 016**	4 049
Net debt	**14 414**	11 254
Shareholders' equity	**44 630**	39 039
Total debt plus shareholders' equity	**62 060**	54 342

Total debt to total debt plus shareholders' equity (%)	**28.1**	28.2

Change in Net Debt

($ millions)	
Net debt – December 31, 2015	11 254
Increase in net debt	3 160
Net debt – December 31, 2016	14 414
Change in net debt	
Cash flow provided by operating activities	5 680
Capital and exploration expenditures	(6 582)
Acquisitions	(1 014)
Cash acquired, COS	109
Debt acquired, COS	(2 639)
Proceeds from disposal of assets	229
Dividends less proceeds from exercise of share options	(1 744)
Change in non-cash investing working capital and other investments	(249)
Issuance of common shares	2 782
Foreign exchange on cash, debt and other balances	268
	(3 160)

At December 31, 2016, Suncor's net debt was $14.414 billion, compared to $11.254 billion at December 31, 2015. During 2016, net debt increased by $3.160 billion, largely due to the acquisitions of COS and Murphy's 5% working interest in Syncrude, and capital and exploration expenditures that exceeded cash flow provided by operating activities net of dividends, partially offset by the issuance of common shares.

For the year ended December 31, 2016, the company's net debt to funds from operations [(1)] measure was 2.4 times, which is lower than management's maximum target of less than 3.0 times.

Subsequent to the end of the year, Suncor has given notice to the Trustee that it intends to repay early, in the second quarter of 2017, the U.S.$1.25 billion 6.10% notes currently scheduled to mature June 1, 2018. The repayment will be funded with the proceeds of asset divestments realized earlier in 2017.

Credit Ratings

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

As at February 28, 2017, the company's long-term senior debt ratings are:

Long-Term Senior Debt	Rating	Long-Term Outlook
Standard & Poor's	A-	Negative
Dominion Bond Rating Service	A (low)	Stable
Moody's Investors Service	Baa1	Stable

The company's commercial paper ratings are:

Commercial Paper	Cdn Program Rating	U.S. Program Rating
Standard & Poor's	A-1 (low)	A-2
Dominion Bond Rating Service	R-1 (low)	Not rated
Moody's Investors Service	Not rated	P2

Refer to the Description of Capital Structure – Credit Ratings section of Suncor's 2016 AIF for a description of credit ratings listed above.

Common Shares

Outstanding Shares

December 31, 2016 (thousands)	
Common shares	**1 667 914**
Common share options – non-exercisable	**17 821**
Common share options – exercisable	**13 621**

As at February 24, 2017, the total number of common shares outstanding was 1,668,994,047 and the total number of exercisable and non-exercisable common share options outstanding was 36,505,300. Once exercisable, each outstanding common share option is convertible into one common share.

(1) Funds from operations was previously referred to as cash flow from operations, with the calculation being unchanged from prior years. Funds from operations and metrics that use funds from operations are non-GAAP financial measures. See the Advisories – Non-GAAP Financial Measures section of this MD&A.

Share Repurchases

Between August 5, 2015 and August 4, 2016, the company was authorized to repurchase common shares for cancellation, with a value up to approximately $500 million, pursuant to a normal course issuer bid (NCIB) through the facilities of the Toronto Stock Exchange, New York Stock Exchange and/or alternative trading platforms. In accordance with applicable securities laws, repurchases under the program were suspended on October 5, 2015, as a result of the offer to the shareholders of COS. During 2016, the company did not make any share repurchases.

Since commencing its share buyback program in 2011, Suncor has purchased 156.7 million common shares for a total return to shareholders of $5.340 billion under this program.

At December 31 ($ millions, except as noted)	**2016**	2015	2014	2013
Share repurchase activities (thousands of common shares)				
Shares repurchased	—	1 230	42 027	49 492
Share repurchase cost ($ millions)	—	43	1 671	1 675
Weighted average repurchase price per share (dollars per share)	—	34.93	39.76	33.84

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

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

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

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

	Payment due by period						
($ millions)	2017	2018	2019	2020	2021	2022 and beyond	Total
Fixed and revolving term debt [1]	2 171	3 978	992	683	2 115	17 846	**27 785**
Finance lease obligations	55	56	22	25	28	948	**1 134**
Decommissioning and restoration costs[2]	382	419	470	552	305	9 553	**11 681**
Operating lease agreements, pipeline capacity and energy services commitments[3]	2 736	1 731	1 509	1 433	1 369	11 374	**20 152**
Exploration work commitments	—	121	97	120	164	66	**568**
Other long-term obligations[4]	2	27	14	14	14	14	**85**
Total	**5 346**	**6 332**	**3 104**	**2 827**	**3 995**	**39 801**	**61 405**

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

(2) Represents the undiscounted amount of decommissioning and restoration costs.

(3) Includes $96 million of commitments pertaining to the company's lubricants business and its interest in the Cedar Point wind facility, which were sold subsequent to December 31, 2016. The company has also entered into various pipeline commitments which are awaiting regulatory approval. In the event regulatory approval is not obtained, Suncor has committed to reimburse certain costs to the service provider.

(4) Includes the Libya ESPA signature bonus and merger consent. See the Other Long-Term Liabilities note to the audited Consolidated Financial Statements.

Transactions with Related Parties

The company enters into transactions with related parties in the normal course of business. These transactions primarily include sales to associated entities in the company's Refining and Marketing segment. For more information on these transactions and for a summary of Compensation of Key Management Personnel, refer to Note 32 to the 2016 audited Consolidated Financial Statements.

Financial Instruments

Suncor periodically enters into derivative contracts for risk management purposes. The derivative contracts hedge risks related to purchases and sales of commodities, to manage exposure to interest rates and to hedge risks specific to individual transactions, such as currency risk associated with repayment of U.S. dollar denominated debt. For the year ended December 31, 2016, the pre-tax earnings impact for risk management activities was a loss of $25 million (2015 – pre-tax gain of $93 million).

The company's Energy Trading business uses crude oil, natural gas, refined products and other derivative contracts to generate net earnings. For the year ended December 31, 2016, the pre-tax earnings impact for Energy Trading activities was a loss of $47 million (2015 – pre-tax gain of $28 million).

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

($ millions)	Energy Trading	Risk Management	Total
Fair value of contracts outstanding – December 31, 2014	20	110	130
Cash settlements – received during the year	(66)	(183)	(249)
Unrealized gains recognized in earnings during the year	28	93	121
Fair value outstanding – December 31, 2015	**(18)**	**20**	**2**
Cash settlements – paid (received) during the year	29	(13)	16
Unrealized losses recognized in earnings during the year	(47)	(25)	(72)
Fair value outstanding – December 31, 2016	**(36)**	**(18)**	**(54)**

The fair value of derivative contracts are recorded in the Consolidated Balance Sheets.

Fair value of derivative contracts at December 31 ($ millions)	**2016**	2015
Accounts receivable	**155**	90
Accounts payable	**(209)**	(88)
	(54)	2

Risks Associated with Derivative Financial Instruments

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

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

For further details on our derivative financial instruments, including assumptions made in the calculation of fair value, a sensitivity analysis of the effect of changes in commodity prices on our derivative financial instruments, and additional discussion of exposure to risks and mitigation activities, see the Financial Instruments and Risk Management note in the company's 2016 audited Consolidated Financial Statements.

9. ACCOUNTING POLICIES AND CRITICAL ACCOUNTING ESTIMATES

Suncor's significant accounting policies are described in Note 3 to the audited Consolidated Financial Statements for the year ended December 31, 2016.

Recently Announced Accounting Pronouncements

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

Statement of Cash Flows

In January 2016, the IASB issued an amendment to IAS 7 *Statement of Cash Flows*. The amendment to IAS 7 requires additional disclosures for changes in liabilities arising from financing activities. This includes changes arising from cash flows, such as drawdowns and repayments of borrowings, and non-cash changes, such as acquisitions, disposals and unrealized exchange differences. The amendment is effective for fiscal years beginning on or after January 1, 2017 and is applied on a prospective basis. The adoption of this standard is not expected to have a material impact on the company's disclosures.

Revenue from Contracts with Customers

In May 2014, the IASB issued IFRS 15 *Revenue from Contracts with Customers*. It replaces existing revenue recognition guidance and provides a single, principles-based five-step model to be applied to all contracts with customers. Retrospective application of this standard is effective for fiscal years beginning on or after January 1, 2018, with earlier application permitted. The adoption of this standard is not expected to have a material impact on the company's disclosure.

Financial Instruments: Recognition and Measurement

In July 2014, IFRS 9 *Financial Instruments* was issued as a complete standard, including the requirements previously issued related to classification and measurement of financial assets and liabilities, and additional amendments to introduce a new expected loss impairment model for financial assets including credit losses. Retrospective application of this standard with certain exemptions is effective for fiscal years beginning on or after January 1, 2018, with earlier application permitted. The adoption of this standard is not expected to have a material impact on the company's disclosure.

Leases

In January 2016, the IASB issued IFRS 16 *Leases* which replaces the existing leasing standard (IAS 17 *Leases*) and requires the recognition of most leases on the balance sheet. IFRS 16 effectively removes the classification of leases as either finance or operating leases and treats all leases as finance leases for lessees with exemptions for short-term leases where the term is twelve months or less and for leases of low-value items. The accounting treatment for lessors remains essentially unchanged, with the requirement to classify leases as either finance or operating remaining. IFRS 16 is effective January 1, 2019, with earlier application permitted. IFRS 16 is expected to significantly increase the company's long-term assets and liabilities, increase depreciation, depletion, amortization and impairment, increase financing expense and reduce operating, selling and general expense. The company has developed a transition team to assess the impact of IFRS 16 and implement the necessary changes to accounting systems, processes and internal controls as a result of the new standard.

Share-Based Payments

In June 2016, the IASB issued the final amendments to IFRS 2 *Share-Based Payments* that clarify the classification and measurement of share-based payment transactions. This includes the effect of vesting and non-vesting conditions on the measurement of cash-settled share-based payments, share-based payment transactions with a net settlement feature for withholding tax obligations, and a modification to the terms and conditions of a share-based payment that changes the classification of the transaction from cash-settled to equity-settled. The amendments are to be applied prospectively and are effective for annual periods beginning on or after January 1, 2018, with earlier application permitted. The company is currently assessing the impact of this standard.

Significant Accounting Estimates and Judgments

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

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

financial condition, changes in financial condition or financial performance.

Significant judgments are those judgments made by management in the process of applying the company's accounting policies and that have the most significant impact on the amounts recognized in the audited Consolidated Financial Statements.

Significant accounting estimates and judgments are reviewed annually by the Audit Committee of the Board of Directors. The following are the significant accounting estimates used in the preparation of Suncor's December 31, 2016 audited Consolidated Financial Statements.

Oil and Gas Reserves

Measurements of depletion, depreciation, impairment, and decommissioning and restoration obligations are determined in part based on the company's estimate of oil and gas reserves. The estimation of reserves and resources is an inherently complex process and involves the exercise of professional judgment. All reserves have been evaluated at December 31, 2016 by independent qualified reserves evaluators. Oil and gas reserves estimates are based on a range of geological, technical and economic factors, including projected future rates of production, projected future commodity prices, engineering data, and the timing and amount of future expenditures, all of which are subject to uncertainty. Estimates reflect market and regulatory conditions existing at December 31, 2016, which could differ significantly from other points in time throughout the year, or future periods. Changes in market and regulatory conditions and assumptions can materially impact the estimation of net reserves.

Oil and Gas Activities

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

Exploration and Evaluation Costs

Certain exploration and evaluation costs are initially capitalized with the intent to establish commercially viable reserves. The company is required to make judgments about future events and circumstances and applies estimates to assess the economic viability of extracting the underlying resources. The costs are subject to technical, commercial and management review to confirm the continued intent to develop the project. Level of drilling success or changes to project economics, resource quantities, expected production techniques, production costs and required capital expenditures are important judgments when making this determination. Management uses judgment to determine when these costs are reclassified to Property, Plant and Equipment based on several factors, including the existence of reserves, appropriate approvals from regulatory bodies and the company's internal project approval process.

Project Development

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

Determination of Cash Generating Units (CGU)

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

Asset Impairment and Reversals

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

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

Regardless of any indication of impairment, the company must complete an annual impairment assessment for any CGU, or group of CGUs, whose net carrying value includes indefinite-life intangible assets or an allocation of goodwill. For Suncor, this includes impairment assessments of the Oil Sands segment as at December 31, 2016 and the Refining and Marketing segment as at October 31, 2016, which determined that the underlying CGUs were not impaired.

As a result of the cost estimate increases for the Fort Hills project, the company completed an impairment assessment

at December 31, 2016 for its share of the project and concluded there was no impairment of the asset.

Decommissioning and Restoration Costs

The company recognizes liabilities for the future decommissioning and restoration of Exploration and Evaluation assets and Property, Plant and Equipment. Management applies judgment in assessing the existence and extent as well as the expected method of reclamation of the company's decommissioning and restoration obligations at the end of each reporting period. Management also uses judgment to determine whether the nature of the activities performed is related to decommissioning and restoration activities or normal operating activities.

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

Suncor's provision for decommissioning and restoration costs increased by $1.8 billion in 2016 to $11.7 billion on an undiscounted basis and increased by $1.3 billion to $6.8 billion on a discounted basis. The most significant change in the provision is related to the additional Syncrude working interests acquired in 2016, partially offset by a decrease in certain cost estimates in the Oil Sands and Exploration and Production segments. The provision also increased due to a decrease in the average credit-adjusted discount rate (2016 – 3.90%; 2015 – 4.37%).

Joint Arrangements

Joint arrangements represent arrangements in which two or more parties have joint control established by a contractual agreement. Joint control requires unanimous consent for financial and operational decisions. Joint arrangements can be classified as either a joint operation or a joint venture. The classification depends on the contractual rights and obligations of each investor, rather than the legal structure of the joint arrangement.

Where the company has rights to the assets and obligations for the liabilities of a joint arrangement, such joint arrangement is classified as a joint operation and the company's share of the assets, liabilities, revenues and expenses is included in the consolidated financial statements.

Where the company has rights to the net assets of an arrangement, the arrangement is classified as a joint venture and accounted for using the equity method of accounting. Under the equity method, the company's initial investment is recognized at cost and subsequently adjusted for the company's share of the joint venture's income or loss, less distributions received.

Control and Significant Influence

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

Employee Future Benefits

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

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

Actuarial valuations are subject to management's judgment. Actuarial gains and losses comprise changes to assumptions related to discount rates, expected return on plan assets and annual rates for compensation increases. They are accounted for on a prospective basis and may have a material impact on the amounts presented.

Other Provisions

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

The company is involved in litigation and claims in the normal course of operations. As at December 31, 2016, management believes the result of any settlements related to such litigation or claims would not materially affect the financial position of the company.

Income Taxes

Management evaluates tax positions, annually or when circumstances require, which involves judgment and could be subject to differing interpretations of applicable tax legislation. The company recognizes a tax provision when a payment to tax authorities is considered probable. However, the results of audits and reassessments and changes in the interpretations of standards may result in changes to those positions, and potentially, a material increase or decrease in the company's assets, liabilities and net earnings.

In 2016, the Tax Court of Canada issued a favourable Order resolving a previously disclosed $1.3 billion tax dispute with the Canada Revenue Agency (CRA). The dispute was regarding the income tax treatment of realized losses in 2007 on the settlement of certain derivative contracts. The Tax Court of Canada Order has confirmed the successful resolution of the matter between Suncor and the CRA, resulting in no additional taxes, interest or penalties. All of the security which Suncor had posted with respect to this item has now been returned to the company.

Deferred Income Taxes

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

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

Fair Value of Financial Instruments

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

Functional Currency

The designation of the functional currency of the company and each of its subsidiaries is a management judgment based on the composition of revenue and costs in the locations in which it operates.

Fair Value of Share-Based Compensation

The fair values of equity-settled and cash-settled share-based payment awards are estimated using the Black-Scholes options pricing model. These estimates depend on certain assumptions, including share price, volatility, risk-free interest rate, the term of the awards, the forfeiture rate and the annual dividend yield, which, by their nature, are subject to measurement uncertainty.

10. RISK FACTORS

Suncor is committed to a proactive program of enterprise risk management intended to enable decision-making through consistent identification and assessment 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.

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 Organization of Petroleum Export Countries (OPEC) members and other countries, 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 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 production from Oil Sands includes significant quantities of bitumen and SCO that trade at a discount to light and medium crude oil. Bitumen and SCO 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 SCO 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 and reserves.

Since the latter half of 2014, world oil prices have declined significantly. While world oil prices have moderately recovered from the low prices that have been experienced since the latter half of 2014, due in part to recently agreed upon quotas by OPEC and certain non-OPEC countries, there can be no assurances that this price recovery will continue or can be sustained. Failure by OPEC and these non-OPEC countries to meet or maintain their agreed upon quotas, in addition to the other factors discussed above, could cause world oil prices to decrease and such decrease could be significant and also lead to greater price volatility. A prolonged period of low and/or volatile commodity prices, particularly for crude oil, could have a material adverse effect on Suncor's business, financial condition, cash flows, reserves, and may also lead to the impairment of assets, or the cancellation or deferral of Suncor's growth projects.

Major Operational Incidents (Safety, Environmental and Reliability)

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 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, amongst others, fires (including forest fires), explosions, blow-outs, power outages, severe winter climate conditions and other extreme weather conditions, railcar incidents or derailments, the migration of harmful substances such as oil spills, gaseous leaks or a release of tailings into water systems, pollution and other environmental risks, and accidents, 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, including, amongst others, the following:

- Suncor's Oil Sands business is 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 interdependent component systems, and other risks inherent to oil sands (mining and in situ) operations;

- For Suncor's E&P 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, or the presence of hydrogen sulphide), premature declines of reservoirs, sour gas releases, uncontrollable flows of crude oil, natural gas or well fluids and other accidents;

- 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, reserves and cash flow.

Government/Regulatory Policy and Compliance

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 possible expropriation or cancellation of contract rights.

Before proceeding with most major projects, including significant changes to existing operations, Suncor must obtain various federal, provincial, state and municipal permits and regulatory approvals. Suncor must also obtain licences to operate certain assets. These processes can involve, among other things, Aboriginal and 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 or a third-party infrastructure project on which a portion of Suncor's business depends. 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 environmental, health and safety (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, denial of 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.

Changes in government policy (including trade policies affecting energy resource exports) or regulation, or the interpretation thereof, or opposition to Suncor's projects or third-party pipeline and infrastructure projects that delay or prevent necessary permits or regulatory approvals could impact Suncor's operations and existing and planned projects. More recently, obtaining such approvals or permits has become more difficult due to increased public opposition and consultation, including Aboriginal consultation requirements. The result of these developments could 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, all of which could have a material adverse effect on Suncor's business, financial condition, reserves, results of operations and cash flow.

Carbon Risk

Public support for climate change action and receptivity to new technologies has grown in recent years. Governments in Canada and around the world have responded to these shifting societal attitudes by adopting ambitious emissions reduction targets and supporting legislation, including measures relating to carbon pricing, clean energy and fuel standards, and alternative energy incentives and mandates. There has also been increased activism and public opposition to fossil fuels and oil sands in particular.

Existing and 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.

Environmental regulation, including regulation relating to climate change, could impact the demand for, formulation or quality of our products, or could require increased capital expenditures, operating expenses and distribution costs, which may or may not be recoverable in the marketplace. In addition, such regulatory changes could necessitate that Suncor develop new technologies. Such technology development could require a significant investment of capital and time, and any delay in or failure to develop such technologies could prevent Suncor from obtaining regulatory approvals for projects or being able to successfully compete with other companies. Increasing environmental regulation in the jurisdictions in which Suncor operates may also make it difficult for Suncor to compete with companies operating in other jurisdictions with fewer or less costly regulations. The complexity and breadth of changes in environmental regulation make it extremely difficult to predict the potential impact to Suncor.

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 will be subject to incremental levies and taxes. There is also a risk that Suncor could face litigation initiated by third parties relating to climate change. In addition, the mechanics of implementation and enforcement of the *Oil Sands Emissions Limit Act* (Alberta) are currently under review and it is not yet possible to predict the impact on Suncor. However, such impact could be material.

These developments and further such developments in the future could adversely impact the demand for Suncor's products, the ability of Suncor to maintain and grow its production and reserves, and Suncor's reputation and could have a material adverse effect on Suncor's business, financial condition, reserves, results of operations and cash flow.

Environmental Compliance

Tailings Management

There are risks associated with Suncor's tailings management plans, including with respect to joint arrangements in which Suncor has an interest. Each mine is required under the Alberta Energy Regulator's Directive 085 – Fluid Tailings Management for Oil Sands Mining Projects to update its mine fluid tailings management plans. If those plans are not approved in the timelines anticipated or at all, the operators' ability to implement additional fluid tailings treatment facilities could be adversely impacted, which could result in reductions in production and lower volumes of treated tailings. If the mine exceeds certain compliance levels specified in the TMF, the applicable company could be subject to enforcement actions, including being required to curtail production, and financial consequences, including being subject to a compliance levy or being required to post additional security under the mine financial security program (MFSP). The full impact of the TMF, including the financial consequences of exceeding compliance levels, is

not yet fully known, as certain associated policies and regulations are still under development. Such policies and regulations could also restrict the technologies that the company may employ for tailings management, which could adversely impact the company's business plans. There could also be risks if the company's tailings management operations fail to operate as anticipated. 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.

Alberta's Land-Use Framework

The implementation of, and compliance with, the terms of the lower Athabasca regional plan (LARP) may adversely impact our current properties and projects in northern Alberta due to, among other things, environmental limits and thresholds. 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. The changes in Suncor's business or operations required as a result of the LARP could have a material adverse effect on Suncor's business, financial condition, reserves, results of operations and cash flow.

Alberta Environment Water Licences

We currently rely on water 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. It is also possible that regional water management approaches may require water sharing agreements between stakeholders. 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 also a risk that future laws or changes to existing laws or regulations relating to water access could cause capital expenditures and operating expenses relating to water licence compliance to increase.

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.

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 costs, as well as affecting Suncor's bitumen blend marketing strategy.

Market access for oil sands production may be constrained by insufficient pipeline takeaway capacity, including as a result of the lack of new pipelines due to an inability to secure required approvals and negative public perception. There is a risk that constrained market access for oil sands production, growing inland production and refinery outages will potentially create 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. In the ordinary course of Suncor's business, Suncor collects and stores sensitive data, including intellectual property, proprietary business information and identifiable personal information of our employees and retail customers. Our operations are also dependent upon a large and complex information framework. We rely on industry accepted security measures and technology to protect Suncor's information systems and securely maintain confidential and proprietary information stored on our information systems, and have adopted a continuous process to identify, assess and manage threats to the company's information systems. Suncor's information security risk oversight is conducted by the Governance Committee. However, these measures and technology may not be adequate due to the increasing volume and sophistication of cyber threats. Suncor's information technology and infrastructure, including process control systems, may be vulnerable to attacks by hackers and cyberterrorists motivated by, among others, geopolitical, financial or activist reasons, or breached due to employee error, malfeasance or other disruptions. Any such attack or breach could compromise Suncor's networks and the information Suncor stores could be accessed, publicly disclosed, lost, stolen or compromised. Any such attack, breach, access, disclosure or loss of information could result in legal claims or proceedings, liability under

laws that protect the privacy of personal information, regulatory penalties, disruptions to Suncor's operations, decreased performance and production, increased costs, and damage to Suncor's reputation, which could have a material adverse effect on Suncor's business, financial condition, results of operations and cash flow. Although the company maintains a risk management program, which includes an insurance component that may provide coverage for certain impacts of attacks to or breaches of Suncor's information technology and infrastructure, including process control systems, such insurance does not address all such impacts and 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 and impacts of any such attack or breach.

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 start-up – 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 Asset Delivery and Execution 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.

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 for Suncor to deliver value to shareholders and stakeholders. These ambitious business objectives 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.

Joint Arrangement Risk

Suncor has entered into joint arrangements and other contractual arrangements with third parties with respect to certain of its projects, including arrangements where other entities operate assets in which Suncor has ownership or other interests. These joint arrangements include, amongst others, those with respect to Syncrude, Fort Hills, and operations in Suncor's E&P Canada and E&P International businesses. 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.

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, the British pound and the Norwegian krone. 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. As at December 31, 2016, the Canadian dollar strengthened slightly in relation to the U.S. dollar to 0.74 from 0.72 at the start of 2016. Exchange rate fluctuations 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. We are also exposed to changes in interest rates on derivative instruments used to manage the debt portfolio, including hedges of prospective new debt issuances. 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 balances and cash equivalents, cash flow provided by operating activities, available committed credit facilities, issuing commercial paper and, if needed, divesting of non-core assets and accessing capital markets. 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 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.

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. Short-term operational constraints on pipeline systems arising from pipeline interruption and/or increased supply of crude oil have occurred in the past and could occur in the future. 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.

Royalties and Taxes

Suncor is subject to royalties and taxes imposed by governments in numerous jurisdictions.

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 such events. The final determination of these events may have a material impact on the company's royalties expense.

An increase in Suncor's royalties expense, income taxes, property taxes, carbon taxes, tariffs, duties, border taxes, and other taxes and government-imposed compliance costs, could have a material adverse effect on Suncor's business, financial condition, reserves, 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 Public Officials Act* (Canada) and the United Kingdom *Bribery Act*;
- Renegotiation of contracts with government entities and quasi-government agencies;
- 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 or local 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, reserves 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 terminal and distribution operations, and our Terra Nova Floating Production, Storage and Offloading are represented by labour unions or employee associations. Approximately 34% of the company's employees were covered by collective agreements at the end of 2016. Negotiations for a new collective agreement are in progress with Unifor at Suncor's Montreal refinery and at Terra Nova. 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, present 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. Although current commodity pricing has slowed certain larger projects in the short term, 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 cause 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 and Aboriginal Consultation

Aboriginal Peoples have claimed Aboriginal title and rights to portions of Western Canada. In addition, Aboriginal Peoples have filed claims against industry participants relating in part to land claims, which may affect our business.

The requirement to consult with Aboriginal Peoples in respect of oil and gas projects and related infrastructure has also increased in recent years. In addition, the Canadian federal government and the provincial government in Alberta have made a commitment to renew their relationships with Aboriginal Peoples of Canada. The federal government has stated it now fully supports the United Nations Declaration on the Rights of Indigenous Peoples (the Declaration) without qualification and that Canada intends "nothing less than to adopt and implement the Declaration in accordance with the Canadian Constitution." The Alberta government is also currently exploring how best to implement the principles and objectives of the Declaration in a way that is consistent with the Constitution and Alberta law. At this time, it is unclear how the Declaration will be adopted into Canadian law and the impact of the Declaration on the Crown's duty to consult with Aboriginal Peoples.

We are unable to assess the effect, if any, that any such land claims or consultation requirements with Aboriginal Peoples may have on our business; however, the impact may be material.

Litigation Risk

There is a risk that Suncor may be subject to litigation, and claims under such litigation 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 and reputational impacts 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, legislative requirements, 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 of Directors considers relevant. There can be no assurance that Suncor will continue to pay dividends in the future.

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.

Other Risk Factors

A detailed discussion of additional risk factors is presented in our most recent Annual Information Form / Form 40-F, filed with the Canadian and U.S. securities regulators, respectively.

11. OTHER ITEMS

Control Environment

Based on their evaluation as of December 31, 2016, Suncor's Chief Executive Officer and Chief Financial Officer concluded that the company's disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the United States Securities Exchange Act of 1934, as amended (the Exchange Act)), are effective to ensure that information required to be disclosed by the company in reports that are filed or submitted to Canadian and U.S. securities authorities is recorded, processed, summarized and reported within the time periods specified in Canadian and U.S. securities laws. In addition, as of December 31, 2016, there were no changes in the internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) that occurred during the year ended December 31, 2016 that have materially affected, or are reasonably likely to materially affect, the company's internal control over financial reporting. Management will continue to periodically evaluate the company's disclosure controls and procedures and internal control over financial reporting and will make any modifications from time to time as deemed necessary.

The effectiveness of our internal control over financial reporting as at December 31, 2016 was audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report, which is included in our audited Consolidated Financial Statements for the year ended December 31, 2016.

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

Corporate Guidance

There have been no changes to the corporate guidance ranges previously issued on November 17, 2016. For further details and advisories regarding Suncor's 2017 corporate guidance, see www.suncor.com/guidance.

12. ADVISORIES

Non-GAAP Financial Measures

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

Operating Earnings (Loss)

Operating earnings (loss) is a non-GAAP financial measure that adjusts net earnings (loss) for significant items that are not indicative of operating performance. Management uses operating earnings (loss) to evaluate operating performance, because management believes it provides better comparability between periods. For the years ended December 31, 2016, December 31, 2015 and December 31, 2014, consolidated operating earnings (loss) are reconciled to net earnings (loss) in the Financial Information section of this MD&A and operating earnings (loss) for each segment are reconciled to net earnings (loss) in the Segment Results and Analysis section of the MD&A. Operating earnings (loss) for the three months ended December 31, 2016 and December 31, 2015 are reconciled to net earnings (loss) below.

Bridge Analyses of Operating Earnings

Throughout this MD&A, the company presents charts that illustrate the change in operating earnings from the comparative period through key variance factors. These factors are analyzed in the Operating Earnings narratives following the bridge analyses in that particular section of the MD&A. These bridge analyses are presented because management uses this presentation to analyze performance.

- The factor for Sales Volumes and Mix is calculated based on sales volumes and mix for the Oil Sands and Exploration and Production segments and throughput volumes and mix for the Refining and Marketing segment.
- The factor for Price, Margin and Other Revenue includes upstream price realizations before royalties, with the exception of Libya, which is net of royalties. Also included are refining and marketing margins, other operating revenues, and the net impacts of sales and purchases of third-party crude, including product purchased for use as diluent in the company's Oil Sands operations and subsequently sold as part of diluted bitumen.
- The factor for Royalties excludes the impact of Libya.
- The factor for Operating and Transportation Expense includes project start-up costs, operating, selling and general expense, and transportation expense.
- The factor for Financing Expense and Other Income includes financing expenses, other income, operational foreign exchange gains and losses, changes in gains and losses on disposal of assets that are not operating earnings adjustments, changes in statutory income tax rates, and other income tax adjustments.

Return on Capital Employed (ROCE)

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

The company presents two ROCE calculations – one including and one excluding the impacts on capital employed of major projects in progress. Major projects in progress includes accumulated capital expenditures and capitalized interest for significant projects still under construction or in the process of being commissioned, and acquired assets that are still

being evaluated. Management uses ROCE excluding the impacts of major projects in progress on capital employed to assess performance of operating assets.

Year ended December 31 ($ millions, except as noted)		**2016**	2015	2014
Adjustments to net earnings				
Net earnings (loss) attributed to common shareholders		**434**	(1 995)	2 699
Add after-tax amounts for:				
Unrealized foreign exchange (gain) loss on U.S. dollar denominated debt		**(524)**	1 930	722
Net interest expense		**304**	312	229
	A	**214**	247	3 650
Capital employed – beginning of twelve-month period				
Net debt		**11 254**	7 834	6 256
Shareholders' equity		**39 039**	41 603	41 180
		50 293	49 437	47 436
Capital employed – end of twelve-month period				
Net debt		**14 414**	11 254	7 834
Shareholders' equity		**44 630**	39 039	41 603
		59 044	50 293	49 437
Average capital employed	B	**57 999**	50 565	48 797
ROCE – including major projects in progress (%)	A/B	**0.4**	0.5	7.5
Average capitalized costs related to major projects in progress	C	**10 147**	7 195	6 203
ROCE – excluding major projects in progress (%)	A/(B-C)	**0.5**	0.6	8.6

Funds from (used in) Operations and Discretionary Free Cash Flow

Funds from (used in) operations (previously referred to as cash flow from (used in) operations, with the calculation being unchanged from prior years) is a non-GAAP financial measure that adjusts a GAAP measure – cash flow provided by (used in) operating activities – for changes in non-cash working capital, which management uses to analyze operating performance and liquidity. Changes to non-cash working capital can include, among other factors, the timing of offshore feedstock purchases and payments for fuel and income taxes, and the timing of cash flows related to accounts receivable and accounts payable, which management believes reduces comparability between periods.

	Oil Sands			Exploration and Production			Refining and Marketing		
Year ended December 31 ($ millions)	**2016**	2015	2014	**2016**	2015	2014	**2016**	2015	2014
Net (loss) earnings	**(1 149)**	(856)	1 776	**190**	(758)	653	**1 890**	2 306	1 767
Adjustments for:									
Depreciation, depletion, amortization and impairment	**3 864**	3 583	4 035	**1 381**	3 106	1 349	**702**	685	646
Deferred income taxes	**(78)**	172	(139)	**(506)**	(1 235)	(115)	**12**	(21)	(46)
Accretion of liabilities	**208**	144	140	**53**	50	44	**7**	7	7
Unrealized foreign exchange (gain) loss on U.S. dollar denominated debt	**—**	—	—	**—**	—	—	**—**	—	—
Change in fair value of financial instruments and trading inventory	**19**	20	(34)	**—**	—	—	**27**	60	(82)
Loss on debt extinguishment	**—**	—	—	**—**	—	—	**—**	—	—
(Gain) loss on disposal of assets	**(33)**	8	3	**—**	(5)	(82)	**(35)**	(109)	(11)
Share-based compensation	**41**	13	22	**12**	9	8	**21**	2	4
Exploration expenses	**—**	—	—	**204**	255	104	**—**	—	—
Settlement of decommissioning and restoration liabilities	**(248)**	(277)	(324)	**(1)**	(5)	(20)	**(20)**	(20)	(20)
Other	**45**	28	(79)	**(20)**	(31)	(32)	**2**	11	(3)
Funds from (used in) operations	**2 669**	2 835	5 400	**1 313**	1 386	1 909	**2 606**	2 921	2 262
(Increase) decrease in non-cash working capital	**(383)**	(27)	1 252	**60**	322	201	**787**	306	(306)
Cash flow provided by (used in) operating activities	**2 286**	2 808	6 652	**1 373**	1 708	2 110	**3 393**	3 227	1 956

Year ended December 31 ($ millions)	Corporate, Energy Trading and Eliminations 2016	2015	2014	Total 2016	2015	2014
Net (loss) earnings	**(486)**	(2 687)	(1 497)	**445**	(1 995)	2 699
Adjustments for:						
Depreciation, depletion, amortization and impairment	**170**	126	110	**6 117**	7 500	6 140
Deferred income taxes	**60**	160	76	**(512)**	(924)	(224)
Accretion of liabilities	**1**	(4)	7	**269**	197	198
Unrealized foreign exchange (gain) loss on U.S. dollar denominated debt	**(458)**	1 967	839	**(458)**	1 967	839
Change in fair value of financial instruments and trading inventory	**(53)**	7	(93)	**(7)**	87	(209)
Loss on debt extinguishment	**99**	—	—	**99**	—	—
Gain on disposal of assets	**—**	(4)	—	**(68)**	(110)	(90)
Share-based compensation	**68**	(6)	72	**142**	18	106
Exploration expenses	**—**	—	—	**204**	255	104
Settlement of decommissioning and restoration liabilities	**—**	—	—	**(269)**	(302)	(364)
Other	**(1)**	105	(27)	**26**	113	(141)
Funds (used in) from operations	**(600)**	(336)	(513)	**5 988**	6 806	9 058
(Increase) decrease in non-cash working capital	**(772)**	(523)	(1 269)	**(308)**	78	(122)
Cash flow (used in) provided by operating activities	**(1 372)**	(859)	(1 782)	**5 680**	6 884	8 936

Discretionary free cash flow is a non-GAAP financial measure that is calculated by taking funds from operations and subtracting sustaining capital, inclusive of associated capitalized interest, and dividends. Discretionary free cash flow reflects cash available for increasing distributions to shareholders and to fund growth investments. Management uses discretionary free cash flow to measure the capacity of the company to increase returns to shareholders and grow the business. The following is a reconciliation of discretionary free cash flow for Suncor's last three years of operations.

($ millions)	2016	2015	2014
Funds from operations	**5 988**	6 806	9 058
Sustaining capital and dividends	**(4 191)**	(4 250)	(4 504)
Discretionary Free Cash Flow	**1 797**	2 556	4 554

Oil Sands Operations and Syncrude Cash Operating Costs

Oil Sands operations and Syncrude cash operating costs are non-GAAP financial measures. Oil Sands operations cash operating costs are calculated by adjusting Oil Sands segment OS&G expense (a GAAP measure based on sales volumes) for i) costs pertaining to Syncrude operations; ii) non-production costs that management believes do not relate to the production performance of Oil Sands operations, including, but not limited to, share-based compensation adjustments, research, and the expense recorded as part of a non-monetary arrangement involving a third-party processor; iii) revenues associated with excess capacity, including excess power generated and sold that is recorded in operating revenue; iv) project start-up costs; and v) the impacts of changes in inventory levels, such that the company is able to present cost information based on production volumes. Syncrude cash operating costs are calculated by adjusting Syncrude OS&G for non-production costs that management believes do not relate to the production performance of Syncrude operations, including, but not limited to, share-based compensation, research and project start-up costs. Oil Sands operations and Syncrude cash operating costs are reconciled in the Segment Results and Analysis – Oil Sands section of this MD&A. Management uses Oil Sands operations and Syncrude cash operating costs to measure Oil Sands operating performance.

Refining Margin and Refining Operating Expense

Refining margin and refining operating expense are non-GAAP financial measures. Refining margin is calculated by adjusting R&M segment operating revenues, other income and purchases of crude oil and products (GAAP measures) for non-refining margin pertaining to the company's supply, marketing, lubricants and ethanol businesses. Refinery operating expense is calculated by adjusting R&M segment OS&G for i) non-refining costs pertaining to the company's supply, marketing, lubricants and ethanol businesses; and ii) non-refining costs that management believes do not relate to the production of refined products, including, but not limited to, share-based compensation and enterprise shared service allocations. Management uses refining margin and refining operating expense to measure operating performance on a production barrel basis.

Year ended December 31 ($ millions, except as noted)	**2016**	2015	2014
Refining gross margin reconciliation			
Gross margin, operating revenues less purchases of crude oil and products	**5 813**	6 311	5 663
Other income	**16**	86	184
Non-refining margin	**(2 403)**	(2 123)	(1 835)
Refining margin	**3 426**	4 274	4 012
Refinery production[(1)] (mbbls)	**168 798**	171 581	168 536
Refining margin ($/bbl)	**20.30**	24.90	23.80
Refining operating expense reconciliation			
Operating, selling and general expense	**2 203**	2 219	2 495
Non-refining costs	**(1 343)**	(1 338)	(1 490)
Refining operating expense	**860**	881	1 005
Refinery production[(1)]	**168 798**	171 581	168 536
Refining operating expense ($/bbl)	**5.10**	5.10	6.00

(1) Refinery production is the output of the refining process, and differs from crude oil processed as a result of volumetric adjustments for non-crude feedstock, volumetric gain associated with the refining process, and changes in unfinished product inventories.

Impact of First-in, First-out Inventory Valuation on Refining and Marketing Net Earnings

GAAP requires the use of a FIFO valuation methodology. For Suncor, this results in a lag between the sales prices for refined products, which reflects current market conditions, and the amount recorded as the cost of sale for the related refinery feedstock, which reflects market conditions at the time when the feedstock was purchased.

Suncor prepares and presents an estimate of the impact of using a FIFO inventory valuation methodology compared to a LIFO methodology, because management uses the information to analyze operating performance and compare itself against refining peers that are permitted to use LIFO inventory valuation under United States GAAP (U.S. GAAP).

The company's estimate is not derived from a standardized calculation and, therefore, may not be directly comparable to similar measures presented by other companies, and should not be considered in isolation or as a substitute for measures of performance prepared in accordance with GAAP or U.S. GAAP.

Measurement Conversions

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

Operating Earnings Reconciliations – Fourth Quarter 2016 and 2015

Three months ended December 31	Oil Sands		Exploration and Production		Refining and Marketing		Corporate, Energy Trading and Eliminations		Total	
($ millions)	**2016**	2015	**2016**	2015	**2016**	2015	**2016**	2015	**2016**	2015
Net earnings (loss) as reported	**276**	(616)	**54**	(1 263)	**524**	506	**(323)**	(634)	**531**	(2 007)
Unrealized foreign exchange loss on U.S. dollar denominated debt	**—**	—	**—**	—	**—**	—	**222**	382	**222**	382
Derecognition and impairments	**40**	386	**—**	1 213	**—**	—	**31**	—	**71**	1 599
Non-cash mark to market gain on interest rate swaps	**—**		**—**	—	**—**		**(188)**	—	**(188)**	—
Operating earnings (loss)	**316**	(230)	**54**	(50)	**524**	506	**(258)**	(252)	**636**	(26)

Funds from Operations Reconciliations – Fourth Quarter 2016 and 2015

Three months ended December 31	Oil Sands		Exploration and Production		Refining and Marketing		Corporate, Energy Trading and Eliminations		Total	
($ millions)	**2016**	2015	**2016**	2015	**2016**	2015	**2016**	2015	**2016**	2015
Net earnings (loss)	**276**	(616)	**54**	(1 263)	**524**	506	**(323)**	(634)	**531**	(2 007)
Adjustments for:										
Depreciation, depletion, amortization and impairment	**1 038**	1 260	**294**	2 063	**196**	176	**73**	30	**1 601**	3 529
Deferred income taxes	**(14)**	(174)	**(44)**	(579)	**(3)**	(36)	**(9)**	54	**(70)**	(735)
Accretion of liabilities	**53**	38	**10**	13	**2**	2	**—**	(2)	**65**	51
Unrealized foreign exchange loss on U.S. dollar denominated debt	**—**	—	**—**	—	**—**	—	**313**	386	**313**	386
Change in fair value of financial instruments and trading inventory	**—**	(14)	**—**	—	**(1)**	(32)	**(271)**	83	**(272)**	37
Gain on disposal of assets	**—**	—	**—**	—	**(21)**	(4)	**—**	(1)	**(21)**	(5)
Share-based compensation	**57**	21	**7**	3	**32**	11	**105**	35	**201**	70
Exploration expenses	**—**	—	**65**	41	**—**	—	**—**	—	**65**	41
Settlement of decommissioning and restoration liabilities	**(55)**	(37)	**(1)**	(3)	**(7)**	(7)	**—**	—	**(63)**	(47)
Other	**17**	(11)	**—**	(18)	**—**	(11)	**(2)**	14	**15**	(26)
Funds from (used in) operations	**1 372**	467	**385**	257	**722**	605	**(114)**	(35)	**2 365**	1 294
Increase (decrease) in non-cash working capital	**217**	(2)	**156**	45	**982**	424	**(929)**	(318)	**426**	149
Cash flow provided by (used in) operating activities	**1 589**	465	**541**	302	**1 704**	1 029	**(1 043)**	(353)	**2 791**	1 443

Common Abbreviations

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

Measurement

bbl	barrel
bbls/d	barrels per day
mbbls/d	thousands of barrels per day
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
mboe	thousands of barrels of oil equivalent
mboe/d	thousands of barrels of oil equivalent per day
mcf	thousands of cubic feet of natural gas
mcfe	thousands of cubic feet of natural gas equivalent
mmcf	millions of cubic feet of natural gas
mmcf/d	millions of cubic feet of natural gas per day
mmcfe	millions of cubic feet of natural gas equivalent
mmcfe/d	millions of cubic feet of natural gas equivalent per day
m^3	cubic metres
MW	Megawatts
MWh	Megawatt hour

Places and Currencies

U.S.	United States
U.K.	United Kingdom
B.C.	British Columbia
$ or Cdn$	Canadian dollars
US$	United States dollars
£	Pounds sterling
€	Euros

Financial and Business Environment

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

Forward-Looking Information

The MD&A contains certain forward-looking information and forward-looking statements (collectively referred to herein as "forward-looking statements") within the meaning of applicable Canadian and U.S. securities laws. Forward-looking statements and other information are 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; the performance of assets and equipment; capital efficiencies and cost savings; applicable laws and government policies, including 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; the satisfaction by third parties of their obligations to Suncor; 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 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", "future", "potential", "opportunity", "would" and similar expressions.

Forward-looking statements in this MD&A include references to:

Suncor's expectations about growth and other projects, the performance, costs and development of its assets, production volumes, and capital expenditures, including:

- *Statements about the Fort Hills mining project, including: that the company estimates the overall cost of the Fort Hills project to be between $16.5 and $17.0 billion; that Suncor's share of the estimated project cost is $8.1 to $8.3 billion; that Suncor's share of Fort Hills' remaining project capital is between $1.6 and $1.8 billion; that the majority of the spend will occur in 2017 and will be completed within Suncor's existing capital guidance range; planned gross production capacity of 194,000 bbls/d; that Suncor's total capital intensity is expected to remain consistent with the original sanction estimate of $84,000 per flowing barrel of bitumen; that first oil continues to remain on track for late 2017 and the expectation that over 90% of nameplate capacity will be achieved within twelve months; technology to be used for mine development, including carbon-rejecting extraction technology expected to allow the mine to produce a higher quality and lower GHG intensity bitumen product that can be sold directly to market; expected project activities in 2017; and that sustaining capital expenditures in 2017 will continue to develop early-works sustaining activities that will support the*

execution of the mine and tailings plan following the commencement of production;

- *Statements about the Hebron project, including: that the field includes a gravity-based structure design supporting a gross oil production rate of 150,000 bbls/d (31,600 boe/d net to Suncor); expected project activity in 2017; Suncor's share of the project cost estimate provided by the project operator of approximately $2.8 billion (+/- 10%); and that first oil at the Hebron project is expected in late 2017;*
- *Statements about the Rosebank future development project, including that it will be complementary to Suncor's existing U.K. portfolio;*
- *Statements about the Oda development project, including: that the company's share of peak oil production from the project is estimated to be 10,500 boe/d; planned work in 2017; and that first oil is expected in 2019;*
- *Plans for sustaining capital at Oil Sands operations, which are expected to focus on planned maintenance, which includes events at Upgrader 1, Upgrader 2 and Firebag. Additional sustaining capital will be directed to maintaining production capacity at existing facilities, primarily related to new well pads for In Situ assets to offset natural production declines, new tailings treatment infrastructure, ongoing modernization of the company's heavy-haul truck fleet, as well as routine maintenance and risk mitigation projects across all facilities;*
- *Oil Sands operations growth capital will continue to focus on the ETF development, which will support market access for Fort Hills' bitumen;*
- *The expectation that well pads under construction will maintain existing production levels at Firebag and MacKay River in future years as production from existing well pads declines;*
- *The expectation that sustaining capital expenditures in 2017 for Syncrude will focus on planned maintenance, and maintaining production capacity;*
- *The opportunity for production growth through low-cost integration, debottlenecks, expansions and increased reliability, plans to leverage Oil Sands operations' and Syncrude's regional expertise and asset base to advance Syncrude and to improve upon existing synergies through asset integration, and operational excellence initiatives targeting improving facility utilization and workforce productivity, including a continued focus on upgrader reliability, and the expectation that this will achieve steady production growth while reducing operating costs;*
- *The primary focus for both cost management and capital discipline in 2017 to continue efforts to sustainably reduce controllable operating costs through elimination of non-critical work and close collaboration with suppliers and business partners, as well as the continued focus on managing investment opportunities, including sustainability priorities, through a robust asset development process and realizing productivity improvements;*
- *Plan for E&P, including: the evaluation of exploration and development opportunities; plans for drilling activities at Terra Nova; and that growth capital in 2017 will include development drilling at White Rose, Hibernia and Terra Nova within E&P Canada, as well as spending for the Oda and Rosebank development projects within E&P International;*
- *The expectation that sustaining capital for Refining and Marketing will focus on planned maintenance events and routine asset replacement; and*
- *Suncor's plan to continue to leverage the Petro-Canada brand to increase non-petroleum revenues through the company's network of convenience stores and car washes.*

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

- *Planned Upgrader 1 maintenance at the end of the first quarter of 2017, with completion anticipated in the second quarter of 2017, and maintenance events at Upgrader 2 and Upgrader 1 scheduled for the second quarter of 2017 and the third quarter of 2017, respectively, as well as a planned turnaround scheduled for Firebag in the second quarter of 2017;*
- *A planned three-week maintenance event at Terra Nova scheduled to commence in the third quarter of 2017; and*
- *A planned maintenance event at the Montreal refinery in the second quarter of 2017.*

Also:

- *Suncor's strategies and commitments, including delivering competitive and sustainable returns to shareholders by focusing on capital discipline, operational excellence and long-term profitable growth, and by leveraging our competitive differentiators of an industry-leading oil sands reserves base, a proven integrated model, financial strength, industry expertise and a commitment to sustainability, and key components of Suncor's strategy, including profitably operating and developing our reserves, optimizing value through integration, achieving industry-leading unit costs in each business segment, and being an industry leader in sustainable development;*

- *Anticipated proceeds from the divestment of non-core assets of $2.0 billion;*
- *The participation agreements signed with the Fort McKay and Mikisew Cree First Nations for the sale of a combined 49% interest in the ETF development for estimated proceeds of approximately $500 million and the expectation that the transactions will close in the third quarter of 2017;*
- *Economic sensitivities;*
- *The company's belief that it does not have any guarantees or off-balance sheet arrangements that have, or are reasonably likely to have, a current or future material effect on the company's financial condition or financial performance, including liquidity and capital resources;*
- *The belief that the company will have the capital resources to fund its planned 2017 capital spending program of $4.8 to $5.2 billion and to meet current and future working capital requirements through cash balances and cash equivalents, cash flow provided by operating activities, available committed credit facilities, issuing commercial paper and, if needed, divesting of non-core assets and accessing capital markets;*
- *The maximum weighted average term to maturity of the short-term investment portfolio is not expected to exceed six months, and all investments will be with counterparties with investment grade debt ratings;*
- *Management of debt levels continues to be a priority for Suncor given the company's long-term growth plans and pricing environment. Suncor believes that a phased and flexible approach to existing and future growth projects should assist Suncor in maintaining its ability to manage project costs and debt levels; and*
- *Suncor's intention to repay early, in the second quarter of 2017, the U.S.$1.25 billion 6.10% notes currently scheduled to mature June 1, 2018 and to fund the repayment with the proceeds of asset divestments realized earlier in 2017.*

Forward-looking statements 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, or changes to, taxes, fees, royalties, duties and other government-imposed compliance costs; changes in environmental and other regulations and policies; 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 (including forest 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 technology and infrastructure 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, including climate change laws; risks and uncertainties associated with closing a transaction for the purchase or sale of a business, asset or 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; risks associated with land claims and Aboriginal consultation requirements; risks relating to litigation; 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 are discussed in further detail throughout this MD&A, including under the heading Risk Factors, and the company's 2016 AIF dated March 1, 2017 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.

The forward-looking statements contained in this MD&A are made as of the date of this MD&A. Except as required by applicable securities laws, we assume no obligation to update publicly or otherwise revise any forward-looking statements or the foregoing risks and assumptions affecting such forward-looking statements, whether as a result of new information, future events or otherwise.

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EXHIBIT 99-2

Management's Discussion and Analysis for the fiscal year ended December 31, 2016, dated March 1, 2017

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EXHIBIT 99-3

Consent of PricewaterhouseCoopers LLP

CONSENT OF INDEPENDENT AUDITOR

We hereby consent to inclusion in this Annual Report on Form 40-F for the year ended December 31, 2016 and the incorporation by reference in the registration statements on Form S-8 (File No. 333-87604), Form S-8 (File No. 333-112234), Form S-8 (File No. 333-118648), Form S-8 (File No. 333-124415), Form S-8 (File No. 333-149532), Form S-8 (File No. 333-161021), Form S-8 (File No. 333-161029) and Form F-10 (File No. 333-212212) of Suncor Energy Inc., of our report dated February 28, 2017 relating to the consolidated financial statements and the effectiveness of internal control over financial reporting, which appears in the Annual Report.

We also consent to the reference to us under the heading "Interests of Experts" in the Annual Information Form incorporated by reference in this Annual Report on Form 40-F which is incorporated by reference in the Registration Statements referred to above.

"*PricewaterhouseCoopers LLP*"

Chartered Professional Accountants
Calgary, Alberta
March 1, 2017

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EXHIBIT 99-3

Consent of PricewaterhouseCoopers LLP

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EXHIBIT 99-4

Consent of GLJ Petroleum Consultants Ltd.

LETTER OF CONSENT

TO: Suncor Energy Inc.
The Securities and Exchange Commission
The Securities Regulatory Authorities of Each of the Provinces and Territories of Canada

Dear Sirs

Re: Suncor Energy Inc.

We refer to the following reports (the "**Reports**") prepared by GLJ Petroleum Consultants Ltd. ("**GLJ**"):

- Reserves Assessment and Evaluation of In Situ Oil Sands Properties — Summary dated February 24, 2017; and
- Reserves Assessment and Evaluation of Oil Sands Mining Properties — Summary dated February 24, 2017,

which provide GLJ's reports on proved and probable reserves evaluations of Suncor Energy Inc.'s Canadian mining and in-situ leases that were evaluated as at December 31, 2016.

We hereby consent to being named and to the use of, reference to and excerpts and information derived from the said Reports by Suncor Energy Inc. in its:

1. Annual Report on Form 40-F for the year ended December 31, 2016 (the " **Form 40-F**") and the incorporation by reference in the registration statements on Form S-8 (File No. 333-87604), Form S-8 (File No. 333-112234), Form S-8 (File No. 333-118648), Form S-8 (File No. 333-124415), Form S-8 (File No. 333-149532), Form S-8 (File No. 333-161021), Form S-8 (File No. 333-161029) and Form F-10 (File No. 333-212212) of Suncor Energy Inc., of our Reports;

2. Annual Report for the year ended December 31, 2016 (the " **Annual Report**") to be filed with the securities regulatory authorities of each of the provinces and territories of Canada; and

3. Annual Information Form dated March 1, 2017 (the " **AIF**"), which is incorporated by reference into the following prospectuses (collectively, the "**Prospectuses**"): (i) the short form base shelf prospectus of Suncor dated June 29, 2016 relating to the sale and issue of debt securities, common shares, preferred shares, subscription receipts, warrants, units, share purchase contracts and share purchase units from time to time in the aggregate principal amount of U.S. $3,000,000,000, and (ii) the short form base shelf prospectus of Suncor dated June 29, 2016 relating to the sale and issue of Series 5 medium term notes, from time to time, in the aggregate principal amount of up to CDN $3,000,000,000.

We have read the Form 40-F, Annual Report, AIF and Prospectuses and have no reason to believe that there are any misrepresentations in the information contained therein that is derived from our Reports

or that are within our knowledge as a result of the services which we performed in connection with the Reports.

Yours truly,

GLJ PETROLEUM CONSULTANTS LTD.

"*Caralyn P. Bennett*"

Caralyn P. Bennett, P. Eng.
Executive Vice President, Chief Strategy Officer

Dated: March 1, 2017
Calgary, Alberta, Canada

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EXHIBIT 99-4

Consent of GLJ Petroleum Consultants Ltd.
LETTER OF CONSENT

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EXHIBIT 99-5

Consent of Sproule Associates Limited and Sproule International Limited

LETTER OF CONSENT

TO: Suncor Energy Inc.
The Securities and Exchange Commission
The Securities Regulatory Authorities of Each of the Provinces and Territories of Canada

Dear Sirs

Re: Suncor Energy Inc.

We refer to the following reports (the "**Reports**") prepared by Sproule Associates Limited and Sproule International Limited:

- Evaluation of the P&NG Reserves of Suncor Energy Inc. in the Newfoundland Offshore Areas dated February 24, 2017;
- Evaluation of the P&NG Reserves of Suncor Energy Inc. in the North America Onshore Properties dated February 24, 2017;
- Evaluation of the P&NG Reserves of Suncor Energy Inc., Norway dated February 24, 2017; and
- Evaluation of the P&NG Reserves of Suncor Energy Inc., UK Properties dated February 24, 2017,

which provide our reports on proved and probable reserves evaluations pursuant to Canadian disclosure requirements of Suncor Energy Inc.'s Canadian onshore and offshore conventional assets and international operations that were evaluated as at December 31, 2016.

We hereby consent to being named and to the use of, reference to and excerpts and information derived from the said Reports by Suncor Energy Inc. in its:

1. Annual Report on Form 40-F for the year ended December 31, 2016 (the " **Form 40-F**") and the incorporation by reference in the registration statements on Form S-8 (File No. 333-87604), Form S-8 (File No. 333-112234), Form S-8 (File No. 333-118648), Form S-8 (File No. 333-124415), Form S-8 (File No. 333-149532), Form S-8 (File No. 333-161021), Form S-8 (File No. 333-161029) and Form F-10 (File No. 333-212212) of Suncor Energy Inc., of our Reports;

2. Annual Report for the year ended December 31, 2016 (the " **Annual Report**") to be filed with the securities regulatory authorities of each of the provinces and territories of Canada; and

3. Annual Information Form dated March 1, 2017 (the " **AIF**"), which is incorporated by reference into the following prospectuses (collectively, the "**Prospectuses**"): (i) the short form base shelf prospectus of Suncor dated June 29, 2016 relating to the sale and issue of debt securities, common shares, preferred shares, subscription receipts, warrants, units, share purchase contracts and share purchase units from time to time in the aggregate principal amount of U.S. $3,000,000,000, and (ii) the short form base shelf prospectus of Suncor dated June 29, 2016 relating to the sale and issue of Series 5 medium term notes, from time to time, in the aggregate principal amount of up to CDN $3,000,000,000.

We have read the Form 40-F, Annual Report, AIF and Prospectuses and have no reason to believe that there are any misrepresentations in the information contained therein that is derived from our Reports or that are within our knowledge as a result of the services which we performed in connection with the Reports.

Sincerely,

Sproule Associates Limited and
Sproule International Limited

"*Cameron P. Six*"

Cameron P. Six, P.Eng.
Chief Operating Officer and Director

Dated: March 1, 2017
Calgary, Alberta, Canada

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EXHIBIT 99-5

Consent of Sproule Associates Limited and Sproule International Limited
LETTER OF CONSENT

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EXHIBIT 99-6

CERTIFICATION

I, Steven W. Williams, certify that:

1. I have reviewed this annual report on Form 40-F of Suncor Energy Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

/s/ STEVEN W. WILLIAMS

Steven W. Williams
President and Chief Executive Officer

DATE: March 1, 2017

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EXHIBIT 99-6

CERTIFICATION

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EXHIBIT 99-7

CERTIFICATION

I, Alister Cowan, certify that:

1. I have reviewed this annual report on Form 40-F of Suncor Energy Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

/s/ ALISTER COWAN

Alister Cowan
Executive Vice President and Chief Financial Officer

DATE: March 1, 2017

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EXHIBIT 99-7

CERTIFICATION

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EXHIBIT 99-8

**CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,
AS ENACTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the annual report of Suncor Energy Inc. (the "Company") on Form 40-F for the fiscal year ending December 31, 2016 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, STEVEN W. WILLIAMS, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ STEVEN W. WILLIAMS

Steven W. Williams
President and Chief Executive Officer
Suncor Energy Inc.

DATE: March 1, 2017

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EXHIBIT 99-8

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350, AS ENACTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

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EXHIBIT 99-9

**CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,
AS ENACTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the annual report of Suncor Energy Inc. (the "Company") on Form 40-F for the fiscal year ending December 31, 2016 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, ALISTER COWAN, Executive Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ ALISTER COWAN

Alister Cowan
Executive Vice President and Chief Financial Officer
Suncor Energy Inc.

DATE: March 1, 2017

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CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350, AS ENACTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

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EXHIBIT 99-10

SUPPLEMENTARY OIL AND GAS DISCLOSURE (unaudited)

The following disclosures are presented in accordance with United States Financial Accounting Standards Board ("FASB") Topic 932 — "Extractive Activities — Oil and Gas" and Subpart 1200 of Regulation S-K ("Subpart 1200") of the United States Securities and Exchange Commission. Disclosures pertaining to the audited consolidated financial statements as at and for the year ended December 31, 2016 (the "2016 Financial Statements") of Suncor Energy Inc. ("Suncor" or the "Company") were prepared in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board and Canadian generally accepted accounting principles contained within Part 1 of the Chartered Professional Accountants Canada Handbook, which differ in material respects from financial statements prepared in accordance with United States generally accepted accounting principles. The 2016 Financial Statements are attached as Exhibit 99.1 to Suncor's annual report on Form 40-F for the year ended December 31, 2016 (the "Form 40-F").

Reserves Data

Reserves data included herein are estimates only and can be significantly impacted by a variety of internal and external factors. For more information on the risks involved when estimating reserves, see the discussion in the "Statement of Reserves Data and Other Oil and Gas Information — Significant Risk Factors and Uncertainties Affecting Reserves" section in Suncor's 2016 Annual Information Form (the "2016 AIF"), which is contained in the Form 40-F. Readers should also see Suncor's Management's Discussion and Analysis for the year ended December 31, 2016, which is attached as Exhibit 99.2 to the Form 40-F (the "2016 Management's Discussion and Analysis").

The reserves data presented herein may differ in relation to the format and the basis from which volumes are economically determined under Subpart 1200 and National Instrument 51-101 — "Standards of Disclosure for Oil and Gas Activities" ("NI 51-101"), as disclosed in the 2016 AIF. Subpart 1200 requires disclosure of net proved reserves, after royalties, using the average of the first-day-of-the-month prices for the twelve month period prior to the end of the reporting period, whereas NI 51-101 requires disclosure of gross and net reserves, estimated using forecast prices and costs. For Suncor's Fort Hills oil sands mining project, the application of constant pricing results in this project being uneconomic such that no reserves are attributed to this property herein. However, when utilizing forecast pricing, as permitted by NI 51-101, this project is economic, and therefore the applicable reserves are attributed thereto as outlined in the 2016 AIF. Similarly, proved undeveloped volumes associated with Suncor's Hebron offshore project are only economic and qualify as proved undeveloped reserves under forecast pricing, as outlined in the 2016 AIF, and uneconomic using constant pricing and therefore these volumes are not attributed as reserves herein.

Net Proved Oil and Gas Reserves [(1)(2)]

The majority of Suncor's oil and gas reserves are in Canada. In order to align with the Company's segmented information in the 2016 Financial Statements, the 2016 Management's Discussion and Analysis and the 2016 AIF, the company presents the following supplementary oil and gas disclosures by showing amounts associated with its Oil Sands segment, which are exclusively in Canada and produce synthetic crude oil ("SCO") and bitumen, separate from other Canadian operations, which are aggregated with Suncor's international operations (collectively, "Exploration and Production") and

produce crude oil, natural gas and natural gas liquids ("NGLs"). Exploration and Production reserves are in onshore and offshore Canada and offshore UK.

At December 31, (net reserves, constant prices and costs)	SCO (mmbbls)		Bitumen (mmbbls)		Crude Oil and NGLs[3] (mmbbls)		Natural Gas (bcf)		Total (mmboe)	
	2016	2015	2016	2015	2016	2015	2016	2015	2016	2015
Proved Developed										
Oil Sands	2 468	1 823	102	99	—	—	—	—	2 570	1 922
Exploration and Production	—	—	—	—	106	120	11	21	108	124
	2 468	1 823	102	99	106	120	11	21	2 678	2 046
Proved Undeveloped										
Oil Sands	572	567	431	454	—	—	—	—	1 003	1 022
Exploration and Production	—	—	—	—	9	32	—	1	9	32
	572	567	431	454	9	32	—	1	1 013	1 054
Proved										
Oil Sands	3 040	2 390	533	554	—	—	—	—	3 573	2 944
Exploration and Production	—	—	—	—	115	153	11	21	117	156
	3 040	2 390	533	554	115	153	11	21	3 690	3 100

Reconciliation of Net Proved Oil and Gas Reserves

(net reserves, constant prices and costs)	Balance December 31 2014	Revisions of Previous Estimates[4]	Improved Recovery	Acquisitions	Extensions and Discoveries[5]	Production	Dispositions	Balance December 31 2015
Oil Sands								
SCO (mmbbls)	2 152	361	—	—	—	(124)	—	2 390
Bitumen (mmbbls)	1 588	(993)	—	—	—	(41)	—	554
Exploration and Production								
Crude oil and NGLs[3] (mmbbls)	234	(45)	—	—	—	(37)	—	152
Natural gas (bcf)	37	(7)	—	—	—	(9)	—	21
Total (mmboe)	3 981	(678)	—	—	—	(203)	—	3 100

(net reserves, constant prices and costs)	Balance December 31 2015	Revisions of Previous Estimates[4]	Improved Recovery	Acquisitions	Extensions and Discoveries[5]	Production	Dispositions	Balance December 31 2016
Oil Sands								
SCO (mmbbls)	2 390	61	—	726	5	(141)	—	3 040
Bitumen (mmbbls)	554	22	—	—	—	(42)	—	533
Exploration and Production								
Crude oil and NGLs[3] (mmbbls)	152	1	—	—	—	(38)	—	115
Natural gas (bcf)	21	(2)	—	—	—	(9)	—	11
Total (mmboe)	3 100	84	—	726	5	(224)	—	3 690

Notes to Reserve Data:

(1) Definitions

a. Net reserves, in relation to Suncor's production and reserves, represents the company's working interest share after deduction of royalty obligations, plus the company's royalty interests in production and reserves.

b. Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible, from a given date forward, from known reservoirs, and under existing economic conditions, operating methods and government regulations.

c. Proved developed oil and gas reserves are those quantities that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and can be expected to be recovered through extraction equipment and

infrastructure installed and operational at the time of the reserves estimate for projects that extract oil and gas by means not involving a well.

d. Proved undeveloped oil and gas reserves are those quantities that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

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

(3) Natural gas liquids reserves are not significant and have been presented in combination with crude oil reserves.

(4) Revisions of previous estimates include changes to proved reserves, resulting from new information (except for an increase in proved acreage) normally obtained from development drilling and production history or resulting from a change in economic factors, such as changes in constant prices used for the reserve evaluation.

(5) Extensions and discoveries are additions to proved reserves from proved acreage of previously discovered reservoirs through additional drilling in periods subsequent to discovery or discovery of new fields with proved reserves or of new reservoirs of proved reserves in old fields.

Capitalized Costs

	At December 31, 2016			At December 31, 2015		
($ millions)	Oil Sands	Exploration and Production	Total	Oil Sands	Exploration and Production	Total
Exploration and evaluation assets[1]	1 893	145	2 038	1 198	483	1 681
Oil and gas properties[2]	16 312	19 021	35 333	13 387	19 248	32 635
Plant and equipment[2]	58 688	1 109	59 797	45 571	1 221	46 792
— accumulated provision[2]	(20 459)	(12 092)	(32 551)	(15 991)	(11 810)	(27 801)
Total	56 434	8 183	64 617	44 165	9 142	53 307

(1) Exploration and evaluation assets largely represent amounts associated with unproved properties, but may include properties with proved reserves for which Suncor's Board of Directors have not sanctioned development. See note 19 of the 2016 Financial Statements.

(2) Oil and Gas Properties, Plant and Equipment and the accumulated provision largely represent amounts associated with proved properties. See note 18 of the 2016 Financial Statements.

Costs Incurred for Property Acquisition, Exploration and Development Activities

	Year ended December 31, 2016			Year ended December 31, 2015		
($ millions)	Oil Sands	Exploration and Production	Total	Oil Sands	Exploration and Production	Total
Unproved property acquisition	684	68	752	18	1	19
Proved property acquisition	10 806	—	10 806	360	—	360
Exploration[1]	45	212	257	157	400	557
Development[2]	4 272	831	5 103	3 553	1 028	4 581
Total	15 807	1 111	16 918	4 088	1 429	5 517

(1) Includes amounts capitalized to Exploration and Evaluation as well as those charged to Exploration Expense on the Consolidated Balance Sheets and the Consolidated Statements of Comprehensive Income, respectively, of the 2016 Financial Statements.

(2) Includes amounts capitalized to Property, Plant and Equipment on the Consolidated Balance Sheets of the 2016 Financial Statements that relate to the Company's decommissioning and restoration activities.

Results of Operations for Oil- and Gas-Producing Activities

($ millions)	Year ended December 31, 2016			Year ended December 31, 2015		
	Oil Sands	Exploration and Production	Total	Oil Sands	Exploration and Production	Total
Operating revenues, net of royalties	9 470	2 231	11 701	9 218	2 345	11 563
Other Income	26	45	71	146	150	296
	9 496	2 276	11 772	9 364	2 495	11 859
Purchases of crude oil and products	548	—	548	319	3	322
Operating, selling and general	5 777	483	6 260	5 220	502	5 722
Transportation	666	86	752	645	98	743
Depreciation, depletion, amortization and impairment	3 864	1 381	5 245	3 583	3 106	6 689
Exploration	30	259	289	120	358	478
(Gain) Loss on disposal of assets	(33)	—	(33)	8	(5)	3
Finance expenses	234	82	316	150	82	232
(Loss) Earnings before Income Taxes	(1 590)	(15)	(1 605)	(681)	(1 649)	(2 330)
Income taxes	(441)	(205)	(646)	175	(891)	(716)
Net (Loss) Earnings	(1 149)	190	(959)	(856)	(758)	(1 614)

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

The standardized measure of discounted future net cash flows relating to Suncor's proved oil and gas reserves are calculated in accordance with FASB Topic 932 — "Extractive Activities — Oil and Gas". Future cash inflows are estimated using the trailing twelve-month average price, which are also used in estimating the entity's proved oil and gas reserves. Future development and production costs, including the associated decommissioning and restoration activities, are calculated by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. The appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, were applied to the future pretax net cash flows, less the tax basis of the properties involved. A prescribed rate of 10% is applied to discount the future net cash flows.

The calculation of the standardized measure of discounted future net cash flows is based upon information prepared by the Company's independent qualified reserves evaluators, and adjusted for decommissioning and restoration activities and future income taxes.

It should not be assumed that the estimates of future net cash flows presented in the tables below represent the fair market value of the reserves. There is no assurance that the price and cost assumptions will be attained and variances could be material. Future changes to income tax, royalty and environmental regulations could also have a significant impact on the respective assumptions. There is no guarantee that the estimates for SCO, bitumen, crude oil and NGLs, and natural gas reserves provided herein will be recovered. Actual SCO, bitumen, crude oil and NGLs, and natural gas reserves may be greater than or less than the estimates provided herein.

The following twelve-month average prices were used to calculate the standardized measure of discounted future net cash flows:

Year	Brent North Sea	WTI Cushing Oklahoma	WCS Hardisty Alberta	Light Sweet Edmonton Alberta	Pentanes Plus Edmonton Alberta	AECO Gas	B.C. Gas Westcoast Station 2	National Balancing Point North Sea
	US$/bbl	US$/bbl	Cdn$/bbl	Cdn$/bbl	Cdn$/bbl	Cdn$/mmbtu	Cdn$/mmbtu	Cdn$/mmbtu
2016	42.82	42.75	39.77	53.67	57.02	2.18	1.63	6.42
2015	54.17	50.28	48.82	61.20	64.19	2.66	1.92	8.42

($ millions)	At December 31, 2016 Oil Sands	Exploration and Production	Total	At December 31, 2015 Oil Sands	Exploration and Production	Total
Future cash inflows	179 213	6 240	185 453	170 803	10 330	181 133
Future production costs	(116 271)	(2 632)	(118 904)	(99 211)	(4 050)	(103 261)
Future development costs	(58 540)	(1 858)	(60 398)	(54 936)	(4 231)	(59 167)
Future income tax expenses	(2 095)	(680)	(2 775)	(4 423)	(982)	(5 405)
Future net cash flows	2 307	1 070	3 377	12 233	1 067	13 300
10% Discount Factor	4 197	206	4 403	(6 560)	264	(6 296)
Standardized measure of discounted future net cash flows	6 504	1 276	7 780	5 673	1 331	7 004

Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

($ millions)	2016	2015
Standardized measure of discounted future net cash flows — beginning of year	7 004	28 018
Sales and transfers of oil and gas produced	(4 689)	(9 701)
Net change in sales prices and operating costs related to future production	(8 192)	(32 402)
Net change due to extensions, discoveries and improved recovery	32	—
Net change due to acquisitions and dispositions	5 063	—
Net change due to revisions in quantity estimates	1 404	1 287
Previously estimated development costs incurred during the period	2 156	2 533
Changes in estimated future development costs	3 035	3 283
Accretion of discount	638	2 564
Net change in income taxes	1 329	11 422
Standardized measure of discounted future net cash flows — end of year	7 780	7 004

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