SUNCOR ENERGY INC
Form 40-F
March 02, 2018

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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, 2017
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, 2017 there were 1,640,983,359 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 for 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 ý No o

Indicate by check mark whether the registrant is an emerging growth company as defined in Rule 12b-2 of the Exchange Act.

Emerging growth company o

If an emerging growth company that prepares its financial statements in accordance with U.S. GAAP, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. 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, 2018, 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, 2017, 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).

ANNUAL INFORMATION FORM

ANNUAL INFORMATION FORM DATED MARCH 1, 2018

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ADVISORIES

In this Annual Information Form (AIF), references to "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 2017 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 auditor's report, as at and for each year in the two-year period ended December 31, 2017. References to the MD&A mean Suncor's Management's Discussion and Analysis, dated March 1, 2018.

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 the 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

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.

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 American Petroleum Institute (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.
>
> **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.

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.

Oil sands are naturally occurring stratified deposits of unconsolidated sand/sandstone and other sedimentary rocks saturated with varying amounts of water and bitumen.

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

Wells

> **Appraisal wells** are drilled into a discovered hydrocarbon accumulation to further understand the extent and size of the accumulation.
>
> **Cuttings reinjection wells** are drilled for the safe disposal of drilling waste, including drill cuttings, mud slurry, old drilling fluids and waste water, in order to minimize the environmental impact.

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

Crude 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.

Diluent is a light hydrocarbon mixture used to blend with bitumen or heavy crude oil to reduce its viscosity so that it can be transported by pipeline.

Downstream refers to the refining of crude oil and the distribution and selling of refined products in retail and wholesale channels.

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

Froth treatment refers to the process of adding a light hydrocarbon to bitumen froth produced in the extraction process in order to separate the bitumen from the water and fine solids in the bitumen froth.

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.

Paraffinic froth treatment (PFT) refers to a froth treatment process whereby a lighter diluent or solvent that contains more paraffin is used, resulting in a higher quality bitumen that can be sold directly to market without further upgrading.

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.

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
m^3/s	cubic metres per second
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, Address 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. The company amended its articles in 1995 to move its 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 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, 2017, 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 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 Suncor's 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 Suncor's downstream business, and procures and markets NGLs and LPG for Suncor's downstream business.
Suncor Energy Ventures Corporation	Alberta	A subsidiary which indirectly owns a 36.74% ownership in the Syncrude joint operation.
Suncor Energy Ventures Partnership	Alberta	This partnership owns a 22% 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 Suncor's U.S. refining and marketing operations are conducted.
International operations		

Suncor Energy UK Limited	U.K.	A subsidiary through which the majority of Suncor's operations in the U.K. are conducted.

The company's remaining subsidiaries each accounted for (i) less than 10% of the company's consolidated assets as at December 31, 2017, and (ii) less than 10% of the company's consolidated operating revenues for the fiscal year ended December 31, 2017. In aggregate, the remaining subsidiaries accounted for less than 20% of each of the company's consolidated assets as at December 31, 2017 and the company's consolidated operating revenues for the fiscal year ended December 31, 2017.

GENERAL DEVELOPMENT OF THE BUSINESS

Overview

Suncor is an integrated energy company headquartered in Calgary, Alberta, Canada. The company is strategically focused on developing one of the world's largest petroleum resource basins Canada's Athabasca oil sands. In addition, Suncor explores for, acquires, develops, produces and markets crude oil and natural gas in Canada and internationally; the company transports and refines crude oil, and markets petroleum and petrochemical products primarily in Canada. The company also conducts energy trading activities focused principally on the marketing and trading of crude oil, natural gas, power and byproducts. Suncor also operates a renewable energy business as part of its 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.

In Situ operations include oil sands bitumen production from Firebag and MacKay River and supporting infrastructure, such as central processing facilities; cogeneration units; hot bitumen infrastructure, including insulated pipelines, diluent import lines and a cooling and blending facility; and associated storage assets such as Suncor's East Tank Farm (ETF) operations specific to In Situ. Production is either upgraded by Oil Sands Base, or blended with diluent and marketed directly to customers.

Oil Sands ventures operations include Suncor's 53.55% interest in the Fort Hills mining project, where Suncor is the operator. The company's interest in Fort Hills increased from its previous 50.8% as a result of the resolution of the commercial dispute regarding project funding among the partners. On December 21, 2017, Suncor acquired an additional 2.26% interest, bringing Suncor's share in the project as at December 31, 2017, to 53.06%. On February 20, 2018, Suncor acquired an additional 0.49% interest in the project, in accordance with the terms of the same dispute settlement agreement. The Fort Hills project includes the mine, primary and secondary extraction facilities, and supporting infrastructure. The ETF facility was expanded in July 2017 to support Fort Hills production. The expanded facilities that blend Fort Hills bitumen for Suncor and the other Fort Hills project partners are described as the East Tank Farm Development (ETFD). On November 22, 2017, the company completed the disposition of a combined 49% ownership interest in the new ETFD to the Fort McKay First Nation and the Mikisew Cree First Nation through the creation of the Thebacha Limited Partnership. Oil Sands ventures operations also include Suncor's 58.74% working interest in the Syncrude oil sands mining, extraction and upgrading facilities, as well as undeveloped mining leases. As at December 31, 2017, Suncor's share in Syncrude was 53.74%. On February 23, 2018, Suncor acquired an additional 5% interest in Syncrude from Mocal Energy Limited (Mocal) for US$730 million, subject to closing adjustments.

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 19.190% in the Hibernia Southern Extension Unit (HSEU)), White Rose (27.5% in the base project and 26.125% in the extensions), and Hebron (21.034%). In addition, Suncor holds interests in several

exploration licences offshore Newfoundland and Labrador. E&P Canada also includes Suncor's working interests in natural gas properties in northeast B.C. On February 7, 2018, Suncor reached an agreement with Canbriam Energy Inc. (Canbriam) to exchange all of Suncor's northeast B.C. mineral landholdings, including associated production, along with additional cash consideration of $52 million for a 37% equity interest in the private natural gas company. The transaction is subject to regulatory approval and is expected to close in March 2018.

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 (30%) and the Oda project (30%). On February 9, 2018, Suncor entered into an agreement with Faroe Petroleum to acquire a 17.5% non-operated interest in the Fenja development project. The transaction is subject to customary closing conditions and regulatory approval and is expected to close in the second quarter of 2018. The first three projects are located in the U.K. sector of the North Sea, while the Oda and Fenja projects are located in the Norwegian North Sea. Suncor also holds interests in several exploration licences offshore of 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; some of these oilfields remain shut in due to political unrest, with the timing of a return to normal operations 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 the company believes 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. Suncor sold the lubricants business in 2017. 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 and 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 Petro-Canada™ and Sunoco™ company-owned locations and branded-dealers, a nationwide commercial road transport network and a bulk sales channel in Canada, as well as through other retail stations and wholesale customers in Colorado.

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.

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.

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), bringing Suncor's interest in the project at that time to 50.8%.

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.

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 maintained the existing oil sands rates, providing certainty and predictability for the industry.

2016

Acquisition of Canadian Oil Sands Limited (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 Oil Company Limited (Murphy), which added a further 17,500 bbls/d of SCO capacity, bringing Suncor's ownership interest in Syncrude at that time to 53.74%.

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.

2017

Sale of Suncor's interest in the Cedar Point wind facility. On January 24, 2017, the company closed the sale of Suncor's 50% share of Cedar Point for gross proceeds of $291 million.

Sale of Petro-Canada Lubricants Inc. (PCLI) business. On February 1, 2017, the company completed the sale of PCLI, including the production and manufacturing facilities in Mississauga, Ontario as well as the global marketing and distribution assets held by PCLI, for gross proceeds of $1.125 billion to a subsidiary of HollyFrontier Corporation (HollyFrontier). The sale of PCLI reinforces the company's commitment to continuously optimize its asset portfolio and focus on core assets.

Suncor commenced a normal course issuer bid (NCIB). Suncor filed its notice of intention to commence a new NCIB to purchase and cancel up to $2.0 billion of the company's shares, beginning on May 2, 2017 and ending on May 1, 2018, through the facilities of the Toronto Stock Exchange, New York Stock Exchange and/or alternative trading platforms. As at December 31, 2017, the company had repurchased 33.2 million common shares at an average price of $42.61 per share, for a total repurchase cost of $1.413 billion.

West White Rose Project sanctioned. Suncor is a non-operating partner with a blended working interest of approximately 26%. The company's share of peak oil production is estimated to be 20,000 bbls/d. First oil is targeted for 2022.

Sale of Suncor's interest in the Ripley wind facility. On July 10, 2017, the company closed the sale of Suncor's 50% share of Ripley for gross proceeds of $48 million.

Sale of 49% equity interest in Suncor's ETFD. On November 22, 2017, the company closed the sale to Fort McKay First Nation and Mikisew Cree First Nation of a 49% equity interest in Suncor's ETFD for gross proceeds of $503 million. The deal represents the largest business investment to date by First Nations in Canada.

US$750 million notes offering. On November 15, 2017, the company issued US$750 million of 4.00% senior unsecured notes due in 2047.

First oil from Hebron. Hebron commenced production of oil on November 27, 2017. At peak, Hebron is expected to produce more than 30,000 bbls/d, net to Suncor.

Repayment of debt. The company repaid US$1.25 billion 6.10% notes, US$600 million 6.05% notes and $700 million 5.80% notes all originally scheduled to mature in the first half of 2018. The reduction in outstanding debt reduced financing costs and has provided ongoing balance sheet flexibility.

Fort Hills commercial dispute resolution. On December 21, 2017, the Fort Hills partners resolved their commercial dispute with respect to funding of project capital and reached an agreement pursuant to which Suncor acquired an additional 2.26% interest in the project for consideration of $308 million. Suncor's share in the project as at December 31, 2017, was 53.06%. On February 20, 2018, Suncor acquired an additional 0.49% interest in the Fort Hills project for consideration of $65 million. Suncor's share in the project is now 53.55%.

Fort Hills PFT bitumen now being produced and shipped to market. During the fourth quarter of 2017, the company continued to test the front end of the plant to mitigate the risk associated with the ramp up in 2018. The bitumen froth from testing was further processed to SCO by Oil Sands operations. The Fort Hills project began producing paraffinic froth-treated bitumen from secondary extraction on January 27, 2018, and the production ramp up to the project's nameplate capacity of 194 mbbls/d (104 mbbls/d, net to Suncor) is progressing on schedule.

2018 Developments

Asset exchange with Canbriam. On February 7, 2018, Suncor reached an agreement with Canbriam to exchange all of Suncor's northeast B.C. mineral landholdings, including associated production, along with additional cash consideration of $52 million for a 37% equity interest in Canbriam, a private natural gas company. The transaction is subject to regulatory approval and is expected to close in March 2018.

Purchased 17.5% participating interest in the Fenja development project. On February 9, 2018, Suncor entered into an agreement with Faroe Petroleum to acquire a 17.5% non-operated interest in the Fenja development project located in the Norwegian North Sea for US$54.5 million. The transaction is subject to customary closing conditions and regulatory approvals and is expected to close in the second quarter of 2018.

Acquisition of additional 5% interest in Syncrude. On February 23, 2018, Suncor acquired an additional 5% interest in Syncrude from Mocal for US$730 million, subject to closing adjustments, adding a further 17,500 bbls/d of SCO capacity and increasing the company's ownership interest to 58.74%.

NARRATIVE DESCRIPTION OF SUNCOR'S BUSINESSES

For a discussion of the environmental and other regulatory conditions, and competitive conditions and seasonal impacts affecting Suncor's 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

Suncor's 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 ultra-low sulphur diesel fuel 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. Production levels and product mix are typically 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's updated and approved tailings management plan involves an increase in treatment capacity using Accelerated De-Watering and treatment of mature fine tailings at Oil Sands Base, including the construction of a Permanent Aquatic Storage Structure. This approach is supported by the construction, operation and ongoing monitoring of a Demonstration Pit Lake, and 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 marked 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 2017, the company mined approximately 169 million tonnes of bitumen ore (2016 129 million tonnes) and processed an average of 307 mbbls/d of mined bitumen in its extraction facilities (2016 238 mbbls/d).

Production figures for the 2016 comparative period reflect the effect of the 2016 forest fires in the Fort McMurray region, which resulted in production being temporarily shut in at the Millennium and North Steepbank mines, Upgrader 1 and Upgrader 2. The forest fires also impacted production at the company's in situ Firebag and MacKay River assets, and the Syncrude joint operation.

Upgrading Facilities

Suncor's upgrading facilities consist of two upgraders: Upgrader 1, which has capacity of approximately 110 mbbls/d of SCO, and Upgrader 2, which has 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 2017, Suncor averaged 318 mbbls/d of upgraded (SCO and diesel) production net of the company's internal consumption (2016 259 mbbls/d), mainly sourced from bitumen provided by both Oil Sands Base and In Situ operations, as well as from bitumen froth production from Fort Hills as a result of testing the front end of the plant.

Other Mining Leases

Suncor, directly and indirectly, owns interests in several other mineable oil sands leases, including Voyageur South and Audet. 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 at Firebag and MacKay River use SAGD technology to produce bitumen from oil sands deposits that are too deep to be mined.

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 and 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 characteristics 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. The Firebag complex has central processing facilities with a total capacity of 203 mbbls/d. Actual production from Firebag varies based on steaming and ramp-up periods for new wells, planned and unplanned maintenance, reservoir conditions and other factors.

As at December 31, 2017, Firebag had 13 well pads in operation, with 173 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 474 MW of electricity. The Firebag site power load requirements are approximately 103 MW and, in 2017, Firebag exported approximately 239 MW of electricity to the Alberta power grid and Oil Sands Base plant. There are also 13 OTSGs at the site for additional steam generation.

During 2017, Firebag production averaged 182 mbbls/d (2016 181 mbbls/d) with a SOR of 2.7 (2016 2.6). Production in the second quarter of 2017 was impacted by the first turnaround of the expanded Firebag central facilities to be completed since the company moved to a five-year turnaround cycle. Production was also impacted by planned upgrader maintenance which was completed in that period.

MacKay River

Production from Suncor's MacKay River operations commenced in 2002. As at December 31, 2017, MacKay River included seven well pads with 110 well pairs either producing or on initial steam injection. The MacKay River central processing facilities have debottlenecked bitumen processing capacity of 38 mbbls/d. TransCanada Energy Ltd. 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.

During 2017, MacKay River production averaged 31 mbbls/d (2016 28 mbbls/d) with a SOR of 3.1 (2016 3.2).

Other In Situ Leases

Suncor owns and operates several other oil sands leases which may support future in situ production, including Lewis, Meadow Creek, OSLO and Chard. As well, Suncor owns 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 February 2018, Suncor submitted an application for the Lewis project to the AER.

Meadow Creek is a SAGD project that is part of Suncor's planned in situ replication strategy. Suncor holds a 75% interest and is operator of the project which is located approximately 40 km south of Fort McMurray. Meadow Creek consists of two independent In Situ projects: Meadow Creek East and Meadow Creek West.

In early 2017, Suncor received AER approval for the Meadow Creek East project. This approval is Suncor's first in situ development approval since Firebag. The project will be developed in two stages with anticipated production of 40 mbbls/d up to 80 mbbls/d, provided economic conditions continue to support such a project. Construction could begin as early as 2020 with first oil expected as early as 2023.

In October 2017, Suncor submitted an application for the Meadow Creek West project to the AER. Meadow Creek West has an anticipated production capacity of 40 mbbls/d. Construction is anticipated to begin in 2022 with first oil expected in 2025.

Oil Sands Ventures Assets

Syncrude

As at December 31, 2017, Suncor held a 53.74% interest in the Syncrude joint operation, which has gross bitumen conversion to SCO capacity of 350 mbbls/d (188 mbbls/d net to Suncor). Subsequent to the end of 2017, the company acquired an additional 5% interest in Syncrude from Mocal, bringing Suncor's interest in Syncrude to 58.74% and adding an additional 17.5 mbbls/d of SCO capacity. 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, Mildred Lake West Extension (MLX-W) and Mildred Lake East Extension (MLX-E), subject to final sanctioning and regulatory approvals, which would consequently extend the life of Mildred Lake by a minimum of 10 years. In 2015, a decision was made by the co-owners to progress with the MLX-W program. The MLX-E program is expected to follow MLX-W development if economic conditions prove suitable. The MLX-W program will sustain bitumen production levels at the Mildred Lake site after resource depletion at the North Mine. The plan proposes to use existing mining and extraction facilities. Regulatory applications for these areas were submitted in 2014 and are awaiting AER review. A response is expected from the AER in the second quarter of 2018 and, provided economic conditions support such a project, sanctioning of MLX-W is expected in late 2019 or early 2020.

The proximity of Syncrude to Oil Sands Base affords an opportunity for cost management and collaboration between the company and Syncrude, that involves exploring the option, subject to approval by Syncrude co-owners, for pipelines connecting Syncrude and Oil Sands Base in order to provide opportunities to optimize assets, including during periods of planned maintenance or interruption. During the second quarter of 2017, due to the facility incident at Syncrude, untreated product was transported by truck and sold by Syncrude to Suncor and subsequently sold to market. In addition, a successful bitumen trucking trial was completed, transporting hot bitumen from Suncor's MacKay River to Syncrude for further upgrading.

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 rich fuel gas from upgrading operations. At Aurora North, Syncrude operates two 80 MW gas turbine power plants to provide electricity.

Syncrude produces a single sweet SCO 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. The updated tailings management plan for Syncrude is pending approval by the AER.

In 2017, Suncor's share of Syncrude production averaged 134 mbbls/d (2016 130 mbbls/d). Sustaining capital expenditures in 2018 for Syncrude are expected to focus on a planned turnaround and capacity maintenance. Production in the second quarter of 2017 was significantly impacted by a facility incident that occurred late in the first quarter of 2017. Syncrude completed the required facility repairs, coker maintenance and the planned upgrader turnaround and returned to normal operating rates by early August 2017.

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 operations are substantially similar to those of Suncor's Oil Sands Base assets; however, Fort Hills uses a PFT process to produce a marketable bitumen product that is partially decarbonized, resulting in a higher quality bitumen and eliminating the need for upgrading facilities.

Suncor holds a 53.55% working interest in Fort Hills and is the operator of the project. The company's interest in Fort Hills increased from its previous 50.8% to 53.06% in December 2017, as a result of the resolution of the commercial dispute regarding project funding among the partners. Suncor's share in the project as at December 31, 2017, was 53.06%. On February 20, 2018, Suncor acquired an additional 0.49% interest in the project, in accordance with the terms of the same dispute settlement agreement, for consideration of $65 million. Suncor's share of the project costs from sanction to December 31, 2017 were $8.7 billion, including the impacts of changes in foreign exchange rates. During the second half of 2017, the mining and primary extraction assets were tested and first bitumen froth was successfully produced. The Fort Hills project began producing PFT bitumen from secondary extraction on January 27, 2018. This Fort Hills bitumen was received by ETFD and successfully transported to market. The second and third trains of secondary extraction are being insulated and expected to start up in the first half of 2018. Fort Hills remains on track to reach 90% capacity by the end of 2018. The Fort Hills project has a gross nameplate capacity of 194 mbbls/d of bitumen (104 mbbls/d net to Suncor).

Other Oil Sands Ventures Leases

Suncor indirectly owns interests in other mineable oil sands leases, including Mildred Lake West, Lease 29 and Aurora South, through the company's 58.74% working interest in the Syncrude joint operation. The company also owns a 36.75% working interest in Joslyn mining leases.

New Technology

Technology is a fundamental component of 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.

Early in 2018, Suncor announced that, following a successful commercial-scale evaluation, the company will proceed with the phased implementation of autonomous haulage systems (AHS) at its operated mine sites, starting with the North Steepbank mine. Autonomous haul trucks, which operate using GPS, wireless communication and perceptive technologies, have demonstrated an ability to maneuver safely, effectively and efficiently in Suncor's operating environment and offer a number of advantages over existing truck and shovel operations, including enhanced safety performance, better operating efficiency and lower operating costs.

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:

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 the company's 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 The Nsolv process uses a waterless, warm vaporized solvent technology with the potential of reducing energy, GHG and water impacts during in situ bitumen recovery. An operating pilot of this new technology was completed in early 2017. Suncor and

Nsolv Corporation are evaluating the results and the potential to scale technology up for deployment in a demonstration facility.

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, ultimate recovery and productivity. Monitoring and evaluation will continue throughout 2018.

Sales of Principal Products

Primary markets for SCO and bitumen production from Suncor's Oil Sands segment, including PFT bitumen from Fort Hills, 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 the company's 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 2017 increased to 101 mbbls/d or 47% (2016 93 mbbls/d or 44%) of total in situ bitumen production.

	2017		2016	
Sales Volumes and Operating Revenues Principal Products	**mbbls/d**	**% operating revenues**	mbbls/d	% operating revenues
SCO and diesel (including Syncrude)	**453.4**	**87**	392.0	88
Bitumen	**110.6**	**12**	117.4	11
Byproducts and other operating revenues[(1)]	**n/a**	**1**	n/a	1
	564.0		509.4	

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

In the normal course of business, Suncor enters into long-term sales agreements for its proprietary sour SCO, which contain varying terms with respect to pricing, volume, expiry and termination.

Distribution of Products

Production from Oil Sands operations, including Fort Hills, is gathered into Suncor's Fort McMurray facilities at the Athabasca Terminal, which is operated by Enbridge Inc. (Enbridge), or the East Tank Farm, which is operated by Suncor, and connected to the Athabasca Terminal. 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 and operated by Suncor. At Edmonton, the product is sold to local refiners, including Suncor, or transferred onto the Enbridge mainline 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, on the Enbridge Athabasca Pipeline or the Enbridge Wood Buffalo Pipeline Extension 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

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. 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, Fort Hills and Syncrude

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

In 2017, Suncor incurred royalties at an average rate of 1% of gross revenue for Oil Sands Base (2016 recovery of 1% due to the impact of prior year audit settlements recorded in 2016) and at an average rate of 6% of gross revenue for Syncrude operations (2016 3%). Oil Sands Base and Syncrude are both in the post-payout phase.

Fort Hills is subject to the same Royalty Framework as Oil Sands Base and Syncrude; however, Fort Hills is in the pre-payout phase.

In Situ

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

In 2017, Suncor incurred royalties at an average rate of 2% of gross revenue for MacKay River (2016 recovery of 1% due to the impact of prior year audit settlements recorded in 2016), which is in the post-payout phase, and royalties at an average rate of 2% of gross revenue for Firebag (2016 1%), 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 four 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. Drilling activities took place at Terra Nova in the second half of 2017 and drilling will continue in 2018. As at December 31, 2017, there were 28 wells: 17 oil production wells, nine water injection wells and two gas injection wells.

In 2017, Suncor's share of Terra Nova production averaged 12 mbbls/d (2016 12 mbbls/d). Annual turnaround maintenance was completed at the Terra Nova facility in September 2017, which lasted approximately five 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, 2017, there were 72 wells: 41 oil production wells, 25 water injection wells, five gas injection wells, and one

water-alternating-gas injection well.

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 2017, there were five oil production wells and seven 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 seven water injection wells, six were drilled using a mobile offshore drill rig at a single drill centre. Water for injection purposes is supplied from the GBS platform via a subsea flowline.

In 2017, Suncor's share of Hibernia production averaged 29 mbbls/d (2016 27 mbbls/d).

White Rose and the White Rose Extensions

White Rose is approximately 350 km southeast of St. John's. Operated by Husky Oil Operations Limited (Husky), 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, 2017, there were 36 wells: 19 oil production wells, 13 water injection wells, three gas storage wells, and one gas injection well.

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. First oil was achieved at North Amethyst in May 2010. Development of the South White Rose Extension began in 2013, with first oil being achieved in June 2015.

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. The second stage, West White Rose Project (WWRP), was sanctioned during the second quarter of 2017 with first oil targeted for 2022. The project is expected to extend the life of the existing White Rose assets, with Suncor's share of peak oil production estimated to be 20 mbbls/d. Major development activity is expected to begin in 2018.

In 2017, Suncor's share of White Rose production averaged 11 mbbls/d (2016 11 mbbls/d). Turnaround maintenance was completed at White Rose in September 2017, which lasted approximately two weeks.

Hebron

The Hebron oilfield is located 340 km southeast of St. John's and is operated by ExxonMobil Canada Properties (ExxonMobil Canada). The development includes a concrete GBS that sits on the ocean floor and supports an integrated topsides deck used for production, drilling and accommodations. At peak, the Hebron project is expected to produce more than 30 mbbls/d, net to Suncor, ramping up over the next several years. Hebron has an oil storage capacity of 1,200 mbbls and 52 well slots. Suncor's share of the post-sanction project cost to first oil was approximately $2.4 billion.

In 2017, activities included sailing the platform to its final offshore location and successfully positioning on the seafloor. Drilling activities commenced in the third quarter of 2017 and will continue throughout 2018. First oil was achieved on November 27, 2017, with Suncor's share of production averaging 0.4 mbbls/d in 2017. As at December 31, 2017, there was one oil production well and one cuttings reinjection well.

Other Assets

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. These licences carry a work commitment from 2018 to 2021. The company also holds interests in 48 significant discovery licences and three exploration licences offshore in this area.

North America Onshore

The North America Onshore business develops and produces natural gas and NGLs in Western Canada. These assets produce approximately 2 mboe/d, primarily natural gas, from the Kobes/Montney assets in northeast B.C., in which Suncor has a 100% working interest.

Subsequent to the end of 2017, Suncor reached an agreement with Canbriam to exchange all of Suncor's northeast B.C. mineral landholdings, including associated production, along with additional cash consideration of $52 million for a 37% equity interest in Canbriam, a private natural gas company. The transaction is subject to regulatory approval and is expected to close in March 2018.

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, 2017, there were 48 wells: 35 oil and gas production wells and 13 water injection wells. In 2017, Suncor's share of Buzzard production averaged 44 mboe/d (2016 46 mboe/d).

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. The GEAD co-owners also hold adjacent exploration licences and continue to explore the region. The facilities have gross production capacity of approximately 76 mboe/d (20 mboe/d net to Suncor). As at December 31, 2017, there were 19 wells: 14 oil and gas production wells and five water injection wells. In 2017, Suncor's share of GEAD production averaged 20 mboe/d (2016 19 mboe/d).

Rosebank

In 2016, Suncor acquired a 30% participating interest in the Rosebank project. 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 an anticipated gross 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.

Oda (Norway)

The Oda field (PL405 licence) was discovered in 2011 and is located 13 km east of the producing Ula field in the southern part of the Norwegian North Sea. Spirit Energy is the operator and Suncor has a 30% working interest. The project was sanctioned in November 2016 and the field will 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) in the second half of 2019. Suncor's share of the post-sanction project cost estimate is approximately $270 million.

Fenja (Norway)

In February 2018, Suncor signed an agreement to acquire a 17.5% participating interest in the Fenja development project (PL586 licence). The transaction is subject to regulatory approval and is expected to close in the second quarter of 2018. The Fenja field, which was discovered in 2014 and is operated by VNG Norge, is located approximately 30 km southwest of the Statoil-operated Njord field in the Norwegian Sea. The plan for development and operation has been submitted to the Ministry of Petroleum and Energy for approval which is expected in the first half of 2018. The field will be developed with two subsea templates with six wells tied back to the Statoil-operated Njord platform. First oil is planned for 2021, with peak production expected to reach 34 mbbls/d (6 mbbls/d net to Suncor) between 2021 and 2022. Suncor's share of the post-sanction project cost estimate is approximately $280 million.

Other Assets

Suncor continues to pursue other opportunities in the North Sea and Norwegian Sea. The company holds interests in 20 exploration licences in the U.K. and Norwegian sectors of these areas.

Other International

Libya

In Libya, Suncor is a signatory to seven EPSAs with the 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 impaired in 2015. Suncor had production and liftings from some of its oilfields in 2017, but others remain shut in due to political unrest. The timing of a return to normal operations in Libya remains uncertain.

The estimated cost of Suncor's remaining exploration work program commitment at December 31, 2017 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. In previous periods, Suncor reported volumes on a 50% working interest share of total production. Suncor's share of production in Libya on an entitlement basis averaged 4.5 mbbls/d in 2017 (2016 0.4 mbbls/d).

Syria

In December 2011, amid continuing unrest in Syria, sanctions were imposed and Suncor declared force majeure under its contractual obligations, suspending its operations in the country. Consequently, the company has ceased recording all production and revenue associated with its Syrian assets. Since 2011, Suncor has not been able to monitor the status of any of its assets in the country, including whether certain facilities have suffered damage, although the company believes some 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.

Sales of Principal Products

Oil and gas production from East Coast Canada, the North Sea and 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:

	2017		2016	
Sales Volumes	**mboe/d**	**% operating revenues**	mboe/d	% operating revenues
E&P Canada				
Crude oil and NGLs	**51.1**	**43**	51.6	46
Natural gas	**1.8**	**0**	2.7	0
E&P International				
Crude oil and NGLs[(1)]	**66.5**	**56**	63.5	53
Natural gas	**1.4**	**1**	1.5	1
Total Exploration and Production				
Crude oil and NGLs	**117.6**	**99**	115.1	99

Natural gas	**3.2**	**1**	4.2	1

(1) E&P International crude oil and NGLs includes production volumes for Libya on an entitlement basis.

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 2017, Terra Nova royalties averaged 16% of gross revenue (2016 23% of gross revenue) due to higher eligible capital expenditures in 2017.

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. For the portion of the HSEU that is contained within the original Hibernia licence area, a tier three royalty ranges between 7.5% and 12.5% of net revenue, depending on the price of WTI.

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.

During 2017, Hibernia (including the HSEU) royalties and NPI combined to average 26% of gross revenue (2016 19% 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 2017, total White Rose royalties averaged 9% of gross revenue (2016 10% 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. During 2017, Hebron royalties averaged 1% of gross revenue.

E&P International

There are no royalties on oil and gas production from the North Sea; however, in the U.K., oil and gas profits in the North Sea are subject to a 40% income tax rate. 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 113.7 mbbls/d in 2017.

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 with HollyFrontier, following the completion of the sale of Suncor's Mississauga lubricants facility in early 2017. Refined products are delivered to distribution terminals and customers via the Trans-Northern Pipeline, 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 368,000 metric tonnes in 2017 (2016 351,000 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 2017, the plant produced 408 million litres of ethanol (2016 414 million litres).

Suncor closed the sale of PCLI, including the production and manufacturing facilities in Mississauga, Ontario as well as the global marketing and distribution assets held by PCLI, to HollyFrontier on February 1, 2017, for gross proceeds of $1.125 billion. HollyFrontier will continue to operate PCLI under the Petro-Canada™ brand.

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. Crude oil is supplied to the Commerce City refinery primarily by 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, 2017 and 2016.

Average Daily Crude Throughput	Montreal		Sarnia		Edmonton		Commerce City	
(mbbls/d, except as noted)	**2017**	2016	**2017**	2016	**2017**	2016	**2017**	2016
Sweet synthetic	**7.9**	5.8	**23.0**	25.0	**52.1**	45.1		
Sour synthetic			**35.7**	26.5	**41.7**	44.6	**11.2**	9.2
Diluted bitumen	**24.3**	25.0			**42.1**	40.1	**7.9**	9.1
Sweet conventional	**86.7**	89.1	**1.4**	0.3		0.5	**66.3**	64.9
Sour conventional	**6.8**	7.7	**20.7**	23.5	**0.7**	1.3	**12.8**	10.4
Heavy conventional								
Total	**125.7**	127.6	**80.8**	75.3	**136.6**	131.6	**98.2**	93.6
Utilization (%)	**92**	93	**95**	89	**96**	93	**100**	95
Equity Crude Processed[(1)]	**7.6**	10.5	**48.9**	36.4	**103.8**	108.2	**11.2**	9.2

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

Refined petroleum production yield mix	Montreal		Sarnia		Edmonton		Commerce City	
(%)	**2017**	2016	**2017**	2016	**2017**	2016	**2017**	2016
Gasoline	**42**	39	**49**	51	**45**	46	**48**	50
Distillates	**34**	34	**39**	37	**50**	50	**35**	34
Other	**24**	27	**12**	12	**5**	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™ brand. As at December 31, 2017, this network consisted of 1,517 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 4.8 million litres per site in 2017 (2016 4.9 million litres) and attracted an estimated 17.5% share (2016 17.2%) of the national retail market.

Suncor's Colorado retail network consists of 44 owned outlets branded Shell®, Exxon® and Mobil®. Suncor also has product supply agreements with 161 Shell®-branded sites in both Colorado and Wyoming, and with 27 Exxon® and Mobil®-branded sites in Colorado. Marketing activities from the retail network 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

Locations	As at December 31 **2017**	2016
Retail Service Stations Canada		
Petro-Canada™-branded	**1 516**	1 492
Sunoco™-branded	**1**	1
	1 517	1 493
Retail Service Stations[(1)] U.S.		
Shell®-branded retail service stations Colorado/Wyoming	**196**	218
Exxon®-branded retail service stations Colorado	**26**	15
Mobil®-branded retail service stations Colorado	**10**	5
	232	238
Wholesale Cardlock Sites Canada		
Petro-Canada™-branded cardlock sites (PETRO-PASS™)	**305**	282

(1) The comparative period has been revised to reflect current period presentation, which includes Shell®, Exxon® and Mobil®-branded sites for which Suncor has exclusive product supply agreements.

	2017		2016	
Sales Volumes	**mbbls/d**	**% operating revenues**	mbbls/d	% operating revenues
Gasoline (includes motor and aviation gasoline)				
Eastern North America	**117.5**		115.2	
Western North America	**125.4**		129.1	
	242.9	**46**	244.3	47
Distillates (includes diesel and heating oils, and aviation jet fuels)				
Eastern North America	**86.8**		76.3	

Western North America	**112.5**		109.8	
	199.3	**37**	186.1	36
Other (includes heavy fuel oil, asphalts, lubricants, petrochemicals, other)				
Eastern North America	**62.4**		61.8	
Western North America	**25.9**		29.2	
	88.3	**17**	91.0	17
	530.5		521.4	

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 currently includes a portfolio of four operating wind power facilities located in Alberta, Saskatchewan and Ontario with a gross installed capacity of 111 MW. In addition, Suncor holds a number of sites for potential future wind and solar power projects that are in various stages of development.

In 2016, the company commenced a sale process for certain assets within the Renewable Energy business. Total gross installed capacity decreased by 176 MW due to the sale of Suncor's interest in the Cedar Point Wind Power Project, which closed on January 24, 2017, and Suncor's interest in the Ripley Wind Power Project, which closed on July 10, 2017.

Suncor's wind power projects as at December 31, 2017:

Wind Power Projects		Ownership Interest (%)	Gross (MW)	Turbines	Completed
Operated by Suncor					
Adelaide	Strathroy, Ontario	75.0	40	18	2014
Non-operated					
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	**2017**	2016
Oil Sands[(1)]	**6 196**	6 006
Exploration and Production	**332**	339
Refining and Marketing[(2)]	**2 737**	3 401
Corporate, Energy Trading and Renewable Energy[(3)]	**3 116**	3 091
Total	**12 381**	12 837

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

(2) The decline in Refining and Marketing primarily relates to the sale of PCLI.

(3) Includes employees from the company's 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 38% of the company's employees were covered by collective agreements at the end of 2017. The majority of the collective agreements, covering 3,774 employees represented by Unifor at various locations, were renewed in 2016. Negotiations are in progress with Teamsters Canada at the Burrard terminal and with Unifor for the ETFD. None of the company's collective agreements are scheduled to expire in 2018.

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 the company's business are set forth in a Standards of Business Conduct Code (the Code), which applies to Suncor's directors, officers, employees and independent contractors, 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 independent contractor 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 of the Board of Directors. A copy of the Code is available on Suncor's website at www.suncor.com.

Suncor has a Supplier Code of Conduct which highlights the values that are important to Suncor and is a guide to the standard of behaviour required of all suppliers, contractors, consultants and other third parties with whom Suncor does business. The Supplier Code of Conduct addresses topics such as safety, human rights, harassment, bribery and corruption and confidential information, among others. Compliance with the Supplier Code of Conduct is a standard requirement for all Suncor supply chain contracts.

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 Suncor's employees and the communities where the company operates, 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 it can influence its 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 create shared value. The policy sets the foundation for 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 the company's stakeholders. The policy reflects Suncor's belief that the company's EH&S efforts are complementary and interdependent with the company's 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 targeted 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 independent contractors 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, 2018, with an effective date of December 31, 2017. Reserves evaluations have not been updated since the effective date and, thus, do not reflect changes in the company's reserves since that date. The preparation date of the information is February 23, 2018.

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, 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, including immaterial amounts of heavy crude oil) and 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 Reserves Data

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 is occurring in Syria and Libya, has resulted in volumes that would otherwise be classified as reserves being classified as contingent 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 the company's 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 SCO 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. Suncor's actual production, revenues, royalties, taxes, and development and operating expenditures with respect to the company's reserves will vary from such estimates, and such variances could be material. Production performance subsequent to the date of the estimate may justify future revision, either upward or downward, if material.

The reserves evaluations are based in part on the assumed success of activities the company intends 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; conversely, lower commodity prices may result in lower reserves. Low commodity 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, a summary of which is 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 require that new technologies be developed. Future development could be adversely impacted if compliance costs result in projects not being economically viable or if required technologies are not developed. Refer to the Risk Factors Carbon Risk section of this AIF.

Political Unrest

As a result of political unrest in Syria, Suncor reclassified all Syria reserves to contingent resources, effective December 31, 2012. Suncor also reclassified all Libya reserves to contingent resources, effective December 31, 2016, due to political unrest in Libya. All Syria and Libya volumes remain classified as contingent resources as at December 31, 2017. 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, 2017
(forecast prices and costs)[2]

	SCO[3]		Bitumen		Light Crude & Medium Crude Oil[4]		Conventional Natural Gas[5]		Total	
	(mmbbls)		(mmbbls)		(mmbbls)		(bcfe)		(mmboe)	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Proved Developed Producing										
Mining	2 134	1 923							2 134	1 923
In Situ	160	151	108	100					268	251
E&P Canada					51	40	20	17	54	43
Total Canada	2 294	2 074	108	100	51	40	20	17	2 456	2 217
North Sea					57	57	2	2	57	57
Total Proved Developed Producing	**2 294**	**2 074**	**108**	**100**	**108**	**97**	**22**	**20**	**2 513**	**2 274**
Proved Developed Non-Producing										
Mining										
In Situ	16	12	22	21					39	33
E&P Canada							2	2		
Total Canada	16	12	22	21			2	2	39	33
North Sea										
Total Proved Developed Non-Producing	**16**	**12**	**22**	**21**			**2**	**2**	**39**	**33**
Proved Undeveloped										
Mining			929	863					929	863
In Situ	575	487	675	572					1 250	1 059
E&P Canada					47	46			47	46
Total Canada	575	487	1 603	1 435	47	46			2 226	1 968
North Sea										
Total Proved Undeveloped	**575**	**487**	**1 603**	**1 435**	**47**	**46**			**2 226**	**1 968**
Proved										
Mining	2 134	1 923	929	863					3 062	2 786
In Situ	751	650	805	692					1 557	1 343
E&P Canada					98	86	21	19	102	90
Total Canada	2 885	2 573	1 734	1 555	98	86	21	19	4 721	4 218

North Sea					57	57	2	2	57	57
Total Proved	**2 885**	**2 573**	**1 734**	**1 555**	**155**	**143**	**24**	**22**	**4 778**	**4 275**
Probable										
Mining	608	544	581	492					1 189	1 036
In Situ	1 216	979	342	262					1 558	1 240
E&P Canada					227	191	6	6	228	192
Total Canada	1 823	1 523	923	754	227	191	6	6	2 975	2 469
North Sea					34	34	4	4	35	35
Total Probable	**1 823**	**1 523**	**923**	**754**	**261**	**225**	**10**	**10**	**3 009**	**2 504**
Proved Plus Probable										
Mining	2 741	2 467	1 510	1 356					4 251	3 823
In Situ	1 967	1 629	1 147	954					3 114	2 583
E&P Canada					326	278	28	25	330	282
Total Canada	4 708	4 096	2 657	2 310	326	278	28	25	7 696	6 687
North Sea					91	91	6	6	92	92
Total Proved Plus Probable	**4 708**	**4 096**	**2 657**	**2 310**	**417**	**369**	**34**	**31**	**7 788**	**6 779**

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, 2017
(forecast prices and costs)[2]

	SCO[3]			Bitumen			Light Crude & Medium Crude Oil[4][5]			Conventional Natural Gas[6]			Total	
	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable	Proved	Probable
	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	bcfe	bcfe	bcfe	mmboe	mmboe
Mining														
December 31, 2016	2 317	617	2 934	879	577	1 455							3 196	1 194
Extensions & Improved Recovery[7]														
Technical Revisions[8]	(47)	(10)	(57)	10	(20)	(10)							(37)	(30
Discoveries[9]														
Acquisitions[10]				40	25	64							40	25
Dispositions[11]														
Economic Factors[12]														
Production[13]	(136)		(136)										(136)	
December 31, 2017	**2 134**	**608**	**2 741**	**929**	**581**	**1 510**							**3 062**	**1 189**
In Situ														
December 31, 2016	746	1 169	1 915	825	410	1 235							1 571	1 579
Extensions & Improved Recovery[7]	4	(4)		2	(2)								6	(6
Technical Revisions[8]	30	50	80	19	(66)	(47)							49	(16
Discoveries[9]														
Acquisitions[10]														

Dispositions[11]														
Economic Factors[12]														
Production[13]	(28)		(28)	(41)		(41)							(69)	
December 31, 2017	**751**	**1 216**	**1 967**	**805**	**342**	**1 147**							**1 557**	**1 558**
E&P Canada														
December 31, 2016							104	206	310	27	8	35	108	208
Extensions & Improved Recovery[7]							2	33	35				2	33
Technical Revisions[6][8]							12	(12)		3	(1)	2	13	(12
Discoveries[9]														
Acquisitions[10]														
Dispositions[11]														
Economic Factors[12]										(3)	(1)	(4)	(1)	
Production[13]							(19)		(19)	(5)		(5)	(20)	
December 31, 2017							**98**	**227**	**326**	**21**	**6**	**28**	**102**	**228**
Total Canada														
December 31, 2016	3 063	1 786	4 849	1 704	987	2 691	104	206	310	27	8	35	4 875	2 981
Extensions & Improved Recovery[7]	4	(4)		2	(2)		2	33	35				8	27
Technical Revisions[8]	(17)	41	23	29	(86)	(57)	12	(12)		3	(1)	2	25	(58
Discoveries[9]														
Acquisitions[10]				40	25	64							40	25

Dispositions[11]														
Economic Factors[12]										(3)	(1)	(4)	(1)	
Production[13]	(164)		(164)	(41)		(41)	(19)		(19)	(5)		(5)	(225)	
December 31, 2017	**2 885**	**1 823**	**4 708**	**1 734**	**923**	**2 657**	**98**	**227**	**326**	**21**	**6**	**28**	**4 721**	**2 975**

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, 2017
(forecast prices and costs)[2]

	SCO[3]			Bitumen			Light Crude & Medium Crude Oil[4][5]			Conventional Natural Gas[6]			Total	
	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable	Proved	Probab
	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	bcfe	bcfe	bcfe	mmboe	mmbo
North Sea														
December 31, 2016							69	32	101	4	4	8	69	3
Extensions & Improved Recovery[7]								2	2					
Technical Revisions[8]							11		12	3		3	12	
Discoveries[9]														
Acquisitions[10]														
Dispositions[11]														
Economic Factors[12]														
Production[13]							(23)		(23)	(4)		(4)	(23)	
December 31, 2017							**57**	**34**	**91**	**2**	**4**	**6**	**57**	3
Other International [14]														
December 31, 2016														
Extensions & Improved Recovery[7]														
Technical Revisions[8]							6		6				6	
Discoveries[9]														

Acquisitions[10]														
Dispositions[11]														
Economic Factors[12]														
Production[13][14]							(6)		(6)				(6)	
December 31, 2017														
Total														
December 31, 2016	3 063	1 786	4 849	1 704	987	2 691	172	238	411	31	12	43	4 944	3 01
Extensions & Improved Recovery[7]	4	(4)		2	(2)		2	35	36				8	2
Technical Revisions[8]	(17)	41	23	29	(86)	(57)	30	(12)	18	6	(1)	4	43	(5
Discoveries[9]														
Acquisitions[10]				40	25	64							40	2
Dispositions[11]														
Economic Factors[12]										(3)	(1)	(4)	(1)	
Production[13]	(164)		(164)	(41)		(41)	(48)		(48)	(9)		(9)	(254)	
December 31, 2017	**2 885**	**1 823**	**4 708**	**1 734**	**923**	**2 657**	**155**	**261**	**417**	**24**	**10**	**34**	**4 778**	**3 00**

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, 2017

(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 include immaterial quantities of Heavy Crude oil as follows: Proved Developed Producing of 2 mmbbls, Proved Undeveloped of 34 mmbbls, Proved of 37 mmbbls, Probable of 74 mmbbls and Proved Plus Probable of 111 mmbbls. Net volumes of Light Crude and Medium Crude oil for E&P Canada include immaterial quantities of Heavy Crude oil as follows: Proved Developed Producing of 2 mmbbls, Proved Undeveloped of 34 mmbbls, Proved of 36 mmbbls, Probable of 67 mmbbls and Proved Plus Probable of 103 mmbbls.

(5) Light Crude and Medium Crude oil Technical Revisions for E&P Canada includes quantities of Heavy Crude oil as follows: Proved of 9 mmbbls and Probable of (9) mmbbls.

(6) Conventional Natural Gas includes immaterial amounts of NGLs (0.2 mmbbls of Proved and 0.3 mmbbls of Proved Plus Probable NGLs).

(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 2017 are primarily a result of sanctioning of the WWRP and infill drilling at Firebag, Terra Nova and Hibernia.

(8) Technical Revisions include changes in previous estimates resulting from new technical data or revised interpretations. Changes in 2017 are primarily due to new information obtained during the year, including drilling results and ongoing field performance, an increase in In Situ volumes forecast to be upgraded, and the movement of a portion of Hebron volumes from Probable to Proved as a result of the commencement of production. For Other International, a technical revision has been made to offset production (refer to Note 14 below).

(9) Discoveries are additions to reserves in reservoirs where no reserves were previously booked as a result of the confirmation of the existence of an accumulation of a significant quantity of potentially recoverable petroleum.

(10) Acquisitions are additions to reserves estimates as a result of purchasing interests in oil and gas properties. Additions in 2017 relate to Suncor's acquisition of an additional 2.26% interest in Fort Hills.

(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 evaluations were conducted.

(14) Other International includes production for Libya based on the company's 50% working interest. Production for Libya is offset by Technical Revisions of an equal amount, since Suncor's Libya assets are classified as contingent resources due to political unrest.

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 Suncor's interest in wells, the total number of wells in which Suncor has an interest; and

(c) in relation to Suncor's interest in 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 or reserves;

(b) in relation to Suncor's interest in 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) for mining assets, through installed extraction equipment and infrastructure that is operational at the time of the reserves estimate. 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.

Future Net Revenues Tables and Notes[1]

Net Present Values of Future Net Revenues Before Income Taxes
as at December 31, 2017
(forecast prices and costs)

	(in $ millions, discounted at % per year)					Unit Value[2]
	0%	5%	10%	15%	20%	($/boe)
Proved Developed Producing						
Mining	31 339	28 803	21 997	17 149	13 866	11.44
In Situ	7 128	6 618	6 108	5 647	5 242	24.32
E&P Canada	674	783	815	814	799	18.90
Total Canada	39 141	36 204	28 920	23 610	19 906	13.04
North Sea	2 485	2 374	2 240	2 108	1 985	39.08
Total Proved Developed Producing	41 626	38 578	31 161	25 718	21 892	13.70
Proved Developed Non-Producing						
Mining						
In Situ	1 124	950	814	707	621	25.04
E&P Canada	1	1	1			1.83
Total Canada	1 124	950	815	708	621	24.85
North Sea						
Total Proved Developed Non-Producing	1 124	950	815	708	621	24.85
Proved Undeveloped						
Mining	13 406	5 955	2 874	1 453	726	3.33
In Situ	30 956	16 580	9 493	5 734	3 601	8.97
E&P Canada	1 476	1 184	940	750	604	20.38
Total Canada	45 838	23 719	13 308	7 937	4 931	6.76
North Sea						
Total Proved Undeveloped	45 838	23 719	13 308	7 937	4 931	6.76
Proved						
Mining	44 745	34 758	24 871	18 602	14 592	8.93
In Situ	39 208	24 148	16 416	12 089	9 464	12.23
E&P Canada	2 150	1 968	1 756	1 564	1 402	19.61
Total Canada	86 103	60 873	43 043	32 254	25 459	10.20

North Sea	2 485	2 374	2 240	2 108	1 985	39.08
Total Proved	88 588	63 247	45 283	34 362	27 445	10.59
Probable						
Mining	26 955	11 459	6 136	3 841	2 672	5.92
In Situ	68 545	19 747	7 868	4 228	2 819	6.34
E&P Canada	9 688	6 364	4 351	3 108	2 299	22.64
Total Canada	105 188	37 570	18 355	11 178	7 790	7.43
North Sea	1 727	1 434	1 176	971	811	33.70
Total Probable	106 915	39 004	19 531	12 148	8 601	7.80
Proved Plus Probable						
Mining	71 699	46 217	31 007	22 443	17 264	8.11
In Situ	107 753	43 894	24 284	16 317	12 283	9.40
E&P Canada	11 839	8 332	6 107	4 672	3 702	21.68
Total Canada	191 291	98 443	61 398	43 432	33 249	9.18
North Sea	4 213	3 808	3 416	3 079	2 796	37.05
Total Proved Plus Probable	195 503	102 251	64 814	46 511	36 045	9.56

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

Net Present Values of Future Net Revenues After Income Taxes[(1)]
as at December 31, 2017
(forecast prices and costs)

	(in $ millions, discounted at % per year)				
	0%	5%	10%	15%	20%
Proved Developed Producing					
Mining	21 885	22 509	17 574	13 894	11 374
In Situ	5 471	5 121	4 743	4 391	4 079
E&P Canada	674	783	815	814	799
Total Canada	28 031	28 413	23 132	19 099	16 252
North Sea	1 321	1 273	1 209	1 142	1 079
Total Proved Developed Producing	29 352	29 686	24 341	20 241	17 331
Proved Developed Non-Producing					
Mining					
In Situ	811	684	585	507	444
E&P Canada					
Total Canada	811	684	585	507	444
North Sea					
Total Proved Developed Non-Producing	811	684	585	507	444
Proved Undeveloped					
Mining	10 507	4 496	2 041	931	376
In Situ	22 250	11 696	6 537	3 828	2 308
E&P Canada	1 231	1 011	812	651	524
Total Canada	33 988	17 204	9 391	5 410	3 208
North Sea					
Total Proved Undeveloped	33 988	17 204	9 391	5 410	3 208
Proved					
Mining	32 392	27 005	19 615	14 825	11 750
In Situ	28 532	17 501	11 865	8 726	6 831
E&P Canada	1 905	1 795	1 627	1 465	1 323
Total Canada	62 830	46 300	33 107	25 016	19 904
North Sea	1 321	1 273	1 209	1 142	1 079

Total Proved	64 151	47 574	34 316	26 158	20 983
Probable					
Mining	19 782	8 288	4 342	2 671	1 834
In Situ	49 798	14 262	5 719	3 117	2 105
E&P Canada	7 080	4 662	3 136	2 194	1 586
Total Canada	76 660	27 212	13 197	7 982	5 524
North Sea	1 032	849	693	571	476
Total Probable	77 692	28 061	13 890	8 552	6 000
Proved Plus Probable					
Mining	52 174	35 293	23 957	17 495	13 584
In Situ	78 331	31 763	17 584	11 843	8 935
E&P Canada	8 985	6 457	4 764	3 659	2 909
Total Canada	139 490	73 513	46 305	32 997	25 428
North Sea	2 353	2 122	1 902	1 713	1 555
Total Proved Plus Probable	141 843	75 635	48 206	34 710	26 983

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

Total Future Net Revenues[(1)]
as at December 31, 2017
(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	190 726	19 595	95 875	25 091	18 826	31 339	9 454	21 885
In Situ	17 236	1 011	7 217	1 363	517	7 128	1 657	5 471
E&P Canada	4 242	875	1 443	131	1 118	674		674
Total Canada	212 204	21 482	104 535	26 585	20 461	39 141	11 110	28 031
North Sea	4 588		1 423	86	594	2 485	1 164	1 321
Total Proved Developed Producing	216 792	21 482	105 958	26 671	21 054	41 626	12 275	29 352
Proved Developed Non-Producing								
Mining								
In Situ	2 358	442	587	180	25	1 124	313	811
E&P Canada	6		4	1		1		1
Total Canada	2 364	442	590	181	26	1 124	313	811
North Sea								
Total Proved Developed Non-Producing	2 364	442	590	181	26	1 124	313	811
Proved Undeveloped								
Mining	59 299	4 429	34 305	5 795	1 364	13 406	2 899	10 507
In Situ	100 431	15 157	32 733	20 425	1 160	30 956	8 706	22 250
E&P Canada	4 003	117	1 350	575	485	1 476	244	1 231
Total Canada	163 733	19 703	68 388	26 795	3 009	45 838	11 849	33 988
North Sea								
Total Proved Undeveloped	163 733	19 703	68 388	26 795	3 009	45 838	11 849	33 988
Proved								
Mining	250 024	24 024	130 180	30 886	20 189	44 745	12 352	32 392

In Situ	120 026	16 610	40 537	21 968	1 703	39 208	10 676	28 532
E&P Canada	8 251	992	2 797	708	1 603	2 150	244	1 906
Total Canada	378 301	41 627	173 514	53 562	23 496	86 103	23 273	62 830
North Sea	4 588		1 423	86	594	2 485	1 164	1 321
Total Proved	382 889	41 627	174 937	53 648	24 090	88 588	24 437	64 151
Probable								
Mining	121 007	15 660	63 876	10 648	3 869	26 955	7 172	19 782
In Situ	196 971	37 355	56 972	32 598	1 501	68 545	18 746	49 798
E&P Canada	22 308	3 508	5 746	2 414	952	9 688	2 609	7 079
Total Canada	340 287	56 524	126 594	45 660	6 321	105 188	28 528	76 660
North Sea	3 050		943	286	94	1 727	695	1 032
Total Probable	343 336	56 524	127 537	45 946	6 415	106 915	29 223	77 692
Proved Plus Probable								
Mining	371 032	39 685	194 056	41 534	24 058	71 699	19 525	52 174
In Situ	316 997	53 965	97 509	54 566	3 204	107 753	29 422	78 331
E&P Canada	30 559	4 501	8 543	3 121	2 555	11 839	2 854	8 985
Total Canada	718 588	98 151	300 108	99 222	29 817	191 291	51 801	139 490
North Sea	7 637		2 365	372	687	4 213	1 860	2 353
Total Proved Plus Probable	726 225	98 151	302 474	99 593	30 504	195 503	53 660	141 843

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

Future Net Revenues by Product Type[1]
as at December 31, 2017
(forecast prices and costs)

(before income taxes, discounted at 10% per year)	$ millions	Unit Value $/boe[2]
Proved Developed Producing		
SCO	26 820	12.93
Bitumen	1 285	12.88
Light Crude & Medium Crude Oil[3]	2 959	31.21
Heavy Crude Oil	76	33.02
Conventional Natural Gas[4]	20	5.99
Total Proved Developed Producing	31 161	13.70
Proved		
SCO	32 607	12.67
Bitumen	8 680	5.58
Light Crude & Medium Crude Oil[3]	3 166	29.35
Heavy Crude Oil	810	22.35
Conventional Natural Gas[4]	24	6.66
Total Proved	45 286	10.59
Proved Plus Probable		
SCO	45 527	11.12
Bitumen	9 765	4.23
Light Crude & Medium Crude Oil[3]	6 872	25.86
Heavy Crude Oil	2 620	25.43
Conventional Natural Gas[4]	31	6.00
Total Proved Plus Probable	64 815	9.56

(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.

In Situ future net revenues disclosed above include estimates of production volumes upgraded to SCO and the associated estimated future sales prices and upgrader operating and sustaining capital costs, based on estimates of upgrader capacity available for processing In Situ volumes. For total Proved Plus Probable reserves, approximately 49 to 52% of Firebag bitumen production is estimated to be upgraded to SCO from 2018 to 2033 and 100% thereafter. These assumptions have resulted in a $3.3 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, 2018. 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 price and cost 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 2018 and 2.0% in 2019 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
2017[9]	54.49	50.95	50.59	62.94	66.93	2.15	1.56	5.47
2018	62.33	57.50	50.61	68.60	72.41	2.43	1.88	7.80
2019	63.93	60.90	56.59	72.02	74.90	2.77	2.33	7.86
2020	66.13	64.13	60.86	74.48	77.07	3.19	2.81	8.26
2021	70.37	68.33	64.56	78.60	81.07	3.48	3.16	8.38
2022	73.23	71.19	66.63	80.84	83.32	3.67	3.35	8.43
2023	75.21	73.15	68.49	82.83	85.35	3.76	3.44	8.57
2024	77.23	75.16	70.63	85.17	87.75	3.85	3.50	8.75
2025	79.26	77.17	72.79	87.53	90.13	3.93	3.58	8.92
2026	81.15	79.01	74.72	89.66	92.32	4.02	3.67	9.10
2027	82.75	80.60	76.31	91.49	94.21	4.10	3.75	9.28
2028	84.39	82.20	77.84	93.31	96.11	4.19	3.84	9.47
2029	86.05	83.83	79.38	95.15	97.99	4.28	3.93	9.66
2030	87.81	85.52	80.99	97.09	99.99	4.37	4.02	9.85
2031	89.55	87.22	82.61	99.02	101.99	4.45	4.09	10.04
2032	91.35	88.98	84.25	101.01	104.04	4.53	4.16	10.25
2033+	+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 2017 reflect the company's historical weighted average prices.

Forecast Foreign Exchange Rates Impacting Forecast Prices

Forecast	US$/Cdn$ Exchange Rate	Cdn$/€ Exchange Rate	Cdn$/£ Exchange Rate
Year			
2018	0.790	1.487	1.709
2019	0.800	1.438	1.656
2020	0.817	1.408	1.622
2021	0.828	1.388	1.600
2022	0.840	1.369	1.577
2023+	0.843	1.364	1.571

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

Values presented in the table for Net Present Values 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 2017 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, 2017
(forecast prices and costs)

($ millions)	2018	2019	2020	2021	2022	Remainder	Total	Discounted At 10%
Proved								
Mining	1 713	1 873	1 301	1 468	1 577	22 954	30 886	14 637
In Situ	542	903	786	1 118	554	18 065	21 968	8 485
E&P Canada	145	100	109	60	97	197	708	516
Total Canada	2 400	2 875	2 197	2 647	2 227	41 216	53 562	23 639
North Sea	8	6	12	6	6	48	86	57
Total Proved	2 408	2 881	2 209	2 653	2 233	41 264	53 648	23 696
Proved Plus Probable								
Mining	1 833	2 042	1 443	1 622	1 735	32 858	41 534	17 150
In Situ	457	789	674	746	643	51 258	54 566	9 414
E&P Canada	560	510	403	301	287	1 061	3 121	2 157
Total Canada	2 851	3 341	2 520	2 668	2 665	85 178	99 222	28 721
North Sea	158	96	13	8	8	89	372	315
Total Proved Plus Probable	3 008	3 437	2 533	2 676	2 673	85 267	99 593	29 036

(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 2018 are expected to include:

Development activities at Fort Hills continue to focus on completion of remaining construction activities in secondary extraction, commissioning and start-up activities, and the safe and reliable ramp up to target production rates. Other Mining development activities include turnaround and major maintenance at Upgrader 1, construction 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, development drilling at Hibernia, White Rose, Terra Nova and Hebron.

For E&P International, development of the Norwegian Oda project, as well as development drilling at Buzzard and GEAD.

Future development costs disclosed above are associated with reserves as evaluated by GLJ and Sproule and are subject to change based on many factors, including economic conditions. Management currently believes that internally generated cash flows, existing and future credit facilities, issuing commercial paper 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, 2017, Suncor estimated its undiscounted, uninflated abandonment and reclamation costs for its upstream assets to be approximately $12.0 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, 2017 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, 2017. Suncor estimates that it will incur $1.4 billion of its identified abandonment and reclamation costs during the next three years (undiscounted: 2018 $0.5 billion, 2019 $0.5 billion, 2020 $0.5 billion), more than 79% 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 $30.5 billion (inflated and undiscounted) has been deducted as abandonment and reclamation costs in estimating the future net revenues from Proved Plus Probable reserves, including $27.3 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)

	2015		2016		**2017**	
	First Attributed	Total at December 31 2015	First Attributed	Total at December 31 2016	**First Attributed**	**Total at December 31 2017**
SCO (mmbbls)						
Mining						
In Situ		584		576		**575**
Total SCO		584		576		**575**
Bitumen (mmbbls)						
Mining	207	1 052		879	**40**	**929**
In Situ		741		694		**675**
Total Bitumen	207	1 792		1 573	**40**	**1 603**
Light Crude & Medium Crude Oil (mmbbls)						
E&P Canada		22	1	19	**1**	**13**
North Sea		10				
Other International[(2)]		51				
Total Light Crude & Medium Crude Oil		83	1	19	**1**	**13**
Heavy Crude Oil (mmbbls)						
E&P Canada		30		27		**34**
North Sea						
Other International[(2)]						
Total Heavy Crude Oil		30		27		**34**
Conventional Natural Gas (bcfe)						
E&P Canada						
North Sea		1				
Other International[(2)]						

Total Conventional Natural Gas			1			
Total (mmboe)	207	2 488	1	2 195	**41**	**2 226**

(1) Figures may not add due to rounding.

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

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

	2015		2016		**2017**	
	First Attributed	Total at December 31 2015	First Attributed	Total at December 31 2016	**First Attributed**	**Total at December 31 2017**
SCO (mmbbls)						
Mining		265	285	285		**282**
In Situ		1 207		1 118		**1 167**
Total SCO		1 473	285	1 403		**1 449**
Bitumen (mmbbls)						
Mining	107	542		577	**25**	**581**
In Situ		250		347		**275**
Total Bitumen	107	791		924	**25**	**856**
Light Crude & Medium Crude Oil (mmbbls)						
E&P Canada	5	88	7	79	**33**	**104**
North Sea		4	10	10	**2**	**12**
Other International[2]		42				
Total Light Crude & Medium Crude Oil	5	133	17	89	**34**	**116**
Heavy Crude Oil (mmbbls)						
E&P Canada		82		84		**73**
North Sea						
Other International[2]						
Total Heavy Crude Oil		82		84		**73**
Conventional Natural Gas (bcfe)[3]						
E&P Canada		2				
North Sea		1	3	3		**3**
Other International[2]						

Total Conventional Natural Gas		3	3	3		**3**
Total (mmboe)	112	2 479	303	2 500	**59**	**2 494**

(1) Figures may not add due to rounding.

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

(3) Includes immaterial amounts of NGLs (less than 0.03 mmbbls).

Undeveloped In Situ reserves, which constitute approximately 56% of Suncor's gross Proved Undeveloped reserves and 58% 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. 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. Development of undeveloped In Situ reserves is a function of processing capacity and the forecasts of the declining production from existing In Situ wells. 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 and may take several years. In Situ undeveloped reserves are related only to those sustaining pads and well pairs required for current producing or sanctioned projects. 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 continuing core hole evaluation, to making pad regulatory application, to having obtained pad regulatory approval, to awaiting final internal approval. Final internal approvals are aligned with declining production from the existing In Situ wells.

Undeveloped Mining reserves constitute approximately 42% of Suncor's gross Proved Undeveloped reserves and 35% of Suncor's gross Probable Undeveloped reserves, and relate to the Fort Hills mining project and the Syncrude MLX-W mining areas, which are well-delineated by core hole drilling. At Fort Hills, the second and third trains of secondary extraction are being insulated and expected to start up in the first half of 2018, and will result in all Undeveloped reserves being reclassified to Developed. An application for regulatory approval has been submitted for the Syncrude MLX-W mining area.

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 8% 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 future drilling at Hebron, and under-drilled or undrilled fault blocks related to areas in Hibernia, White Rose and Terra Nova. 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, 2017. For lands in which Suncor holds interests in different formations under the same surface area pursuant to separate leases, the area has been counted for each lease.

Country	Gross Hectares	Net Hectares
Canada	4 600 823	3 298 444
Libya	3 117 800	1 422 900
Syria	345 194	345 194
Norway	458 936	228 661
U.K.	110 530	33 194
Australia (overriding royalty interest only)	113 027	
Total	8 746 310	5 328 393

Suncor's unproved properties 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, or, in the case of Libya and Syria, political unrest. 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 2018, Suncor's rights to 60,154 net hectares in Canada, 23,947 net hectares in Norway and 14,689 net hectares in the U.K. are scheduled to expire. The expiries include approximately 4,096 net hectares in In Situ and 15,438 net hectares in Mining. Substantial portions of expiring lands may have their tenure continued beyond 2018 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, 2017.

	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]	321.0	321.0	88.0	88.0				
British Columbia					31.0	28.5	26.0	22.9
Newfoundland and Labrador	75.0	18.7	6.0	1.9				
North Sea	40.0	11.5	9.0	2.7				
Other International[5]			419.0	211.1			6.0	6.0
Total	436.0	351.2	522.0	303.7	31.0	28.5	32.0	28.9

(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 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, 2017.

($ millions)	Exploration Costs	Proved Property Acquisition Costs	Unproved Property Acquisition Costs	Development Costs	Total
Canada Mining and In Situ	19	335		4 505	4 859
Canada E&P Canada	24			531	555
Total Canada	**43**	**335**		**5 036**	**5 414**
North Sea	64			73	137
Other International	9				9
Total	**116**	**335**		**5 109**	**5 560**

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, 2017.

	Exploratory Wells[1]		Development Wells	
Total number of wells completed	Gross	Net	Gross	Net
Canada Oil Sands				
Oil			14.0	14.0
Service[2]	1.0	1.0	9.0	9.0
Stratigraphic Test[3]			574.0	363.9
Total	**1.0**	**1.0**	**597.0**	**386.9**
Canada E&P Canada				
Oil			9.0	2.0
Dry Hole	1.0	0.2	1.0	0.4
Natural Gas			1.0	1.0
Service[2]			3.0	0.6
Stratigraphic Test				
Total	**1.0**	**0.2**	**14.0**	**4.0**

North Sea	
Oil	
Service[(2)]	
Dry Hole	
Stratigraphic Test	
Total	

(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, disposal wells, and cuttings reinjection wells.

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

Significant exploration and development activities in 2017 included:

For Mining, at Fort Hills, the mining and primary extraction assets began producing. As well, stratigraphic test well drilling programs and other survey work were conducted at Oil Sands Base, Fort Hills 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 and drilling activities at Hebron, development drilling for White Rose, Hibernia and Terra Nova, as well as development work on the Norwegian Oda project.

For significant exploration and development activities expected to occur in 2018 and beyond, see Narrative Description of Suncor's Businesses and Future Development Costs herein.

Production History[1]

2017	Q1	Q2	Q3	Q4	Year Ended
Canada Oil Sands					
Total production (mbbls/d)	**590.6**	**413.6**	**628.4**	**621.2**	**563.7**
Bitumen (mbbls/d)	**115.7**	**64.0**	**144.9**	**121.9**	**111.7**
($/bbl)					
Average price realized[2]	28.46	30.55	34.32	38.94	33.60
Royalties	(0.54)	(0.69)	(0.50)	(1.02)	(0.71)
Production costs	(9.98)	(14.05)	(8.26)	(7.61)	(9.59)
Netback[5]	17.94	15.81	25.56	30.31	23.30
SCO and diesel (mbbls/d)	**332.8**	**288.6**	**324.4**	**324.9**	**317.7**
($/bbl)					
Average price realized[2]	62.40	60.48	56.04	66.40	61.40
Royalties	(0.59)	(1.19)	(1.03)	(1.14)	(0.98)
Production costs	(24.56)	(28.29)	(24.94)	(26.61)	(26.06)
Netback[5]	37.22	31.00	30.07	38.65	34.36
Syncrude (mbbls/d)	**142.1**	**61.0**	**159.1**	**174.4**	**134.3**
($/bbl)					
Average price realized[2]	65.99	60.44	60.30	73.28	66.05
Royalties	(2.96)		(3.18)	(7.94)	(4.32)
Production costs	(39.70)	(90.72)	(31.48)	(28.81)	(39.46)
Netback[5]	23.33	(30.28)	25.64	36.53	22.27
Canada Light Crude & Medium Crude Oil[3]					

Total production (mbbls/d)	**58.1**	**53.9**	**41.4**	**54.1**	**51.8**
($/bbl)					
Average price realized[2]	68.03	64.66	65.10	79.22	69.16
Royalties	(15.94)	(14.05)	(13.01)	(13.21)	(14.26)
Production costs	(9.28)	(10.58)	(14.72)	(11.16)	(11.24)
Netback[5]	42.81	40.03	37.37	54.85	43.66
North Sea Light Crude & Medium Crude Oil[1]					
Total production (mboe/d)	**69.2**	**65.4**	**64.8**	**54.5**	**63.4**
($/boe)					
Average price realized[2]	65.74	61.58	61.22	74.66	65.44
Royalties					
Production costs	(3.75)	(4.57)	(4.51)	(5.89)	(4.62)
Netback[5]	61.99	57.01	56.71	68.77	60.82

(1) Production and liftings in Libya were intermittent in 2017 and not 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 important fields for the year ended December 31, 2017.

	SCO	Bitumen	Light & Medium Oil
	mbbls/d	mbbls/d	mbbls/d
Mining Suncor	239.0		
Mining Syncrude	134.3		
Firebag	78.8	80.6	
MacKay River		31.1	
Buzzard			43.8
GEAD			19.6
Hibernia			28.5
White Rose			11.4
Terra Nova			11.5
Hebron			0.4
Total	452.1	111.7	115.2

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

Production Estimates

The table below outlines the production estimates for 2018 that are included in the estimates of gross Proved reserves and gross Probable reserves as at December 31, 2017. Total Proved production estimates include 219.5 mbbls/d of SCO from Suncor's mining operations (excluding Syncrude), which represents approximately 30% of total estimated production for 2018, 143.8 mbbls/d of SCO from Syncrude, which represents approximately 20% of total estimated production for 2018, and 173.5 mbbls/d of SCO and bitumen from Firebag, which represents approximately 24% of total estimated production for 2018. Total Proved plus Probable production estimates include 232.5 mbbls/d of SCO from Suncor's mining operations (excluding Syncrude), which represents approximately 30% of total estimated production for 2018, 154.3 mbbls/d of SCO from Syncrude, which represents approximately 20% of total estimated production for 2018, and 185.1 mbbls/d of SCO and bitumen from Firebag, which represents approximately 24% of total estimated production for 2018.

	SCO		Bitumen		Light & Medium Crude Oil		Conventional Natural Gas		Total	
	(mbbls/d)		(mbbls/d)		(mbbls/d)		(mmcfe/d)[1]		(mmboe/d)[2]	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Canada										

Proved	442	430	196	188	42	34	10	9	682	653
Probable	28	27	14	11	15	14			57	52
Proved Plus Probable	470	457	210	199	57	48	10	9	739	705
North Sea										
Proved					43	43	5	5	44	44
Probable					3	3	1	1	4	4
Proved Plus Probable					47	47	6	6	48	48
Total[(1)(2)]										
Proved	442	430	196	188	85	77	14	14	726	697
Probable	28	27	14	11	19	17	1	1	61	56
Proved Plus Probable	470	457	210	199	104	94	16	15	787	753

(1) Conventional Natural Gas includes immaterial amounts of NGLs.

(2) Figures 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, 2017. These commitments run through 2020 and beyond, and are primarily for conducting seismic programs and drilling exploration wells.

Country/Area ($ millions)	2018	2019	2020+	Total
Canada		2	44	46
Other International		113	337	450

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 2017. A description of Suncor's use of such instruments is provided in the 2017 audited Consolidated Financial Statements and related MD&A for the year ended December 31, 2017.

Tax Horizon

In 2017, Suncor was subject to cash tax in the majority of the jurisdictions in which it generates earnings, including earnings related to its Canadian, North Sea and Other International production. Based on projected future net earnings, Suncor is expected to be cash taxable on the majority of its Canadian earnings in 2018.

INDUSTRY CONDITIONS

The oil and natural gas industry is subject to extensive controls and regulations governing its operations. 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 Suncor operates, 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 oil other than heavy crude oil (in either case, 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 oil other than heavy crude oil or does not exceed two years for heavy crude oil, the exporter is required to obtain an order from the NEB approving such export.

The NEB has proposed amendments to the current regulations governing the issuance of export licences and orders, intended to reflect changes to the *National Energy Board Act* set out in the federal *Jobs, Growth and Long-Term Prosperity Act*, which received Royal Assent on June 29, 2012. In the transition period, the NEB has issued, and is currently requiring applicants to follow, the *Interim Memorandum of Guidance concerning Oil and Gas Export Applications and Gas Import Applications under Part VI of the National Energy Board Act*.

In February 2018, the federal government issued Bill C-69, *An Act to enact the Impact Assessment Act and the Canadian Energy Regulator Act, to amend the Navigation Protection Act and to make consequential amendments to other Acts* (Bill C-69), which among other things, proposes changes to the NEB regime. The changes proposed in Bill C-69, if and when adopted into law, do not materially alter the current requirements around oil exports. However, at this stage, it is not certain whether or when the federal government might issue new or revised regulations that might impact the oil export regime currently in place.

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, subject to certain conditions, and 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.

As the current U.S. administration has indicated its intention to renegotiate or withdraw from NAFTA, and renegotiation talks between Canada, the United States and Mexico remain ongoing, at this time, Suncor is unable to predict whether such renegotiation will ultimately result in an amendment to NAFTA (or a potential termination of NAFTA in the event negotiations are unsuccessful) 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 and other large oil and natural gas producing countries, 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 governments 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 2017 was 15% for active business income, including resource income. The average provincial income tax rate for Suncor in 2017 was 12.01%.

Other Jurisdictions

Operations in the U.S. have been subject to the U.S. federal tax rate of 35% and various state-level taxes, primarily 4.63% in Colorado. Effective January 1, 2018, the federal tax rate has decreased to 21%, and the effective rate for state taxes is approximately 2.5%, resulting in a total U.S. income tax rate of approximately 23.5%.

Operations in the U.K. are subject to a tax rate of 40%, 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 2017 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.

Under the company's EPSAs in Libya, the NOC remits taxes on Suncor's behalf. Until tax clearance certificates from tax authorities are received, Suncor records both an income tax payable to the taxation authority and an offsetting receivable from the NOC.

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 and offshore 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 laws, including additional legislation for air pollution and GHG emissions, that will impose further requirements on companies operating in the energy industry.

A number of environmentally related 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, biodiversity, air emissions and land use. 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 environmental laws and regulations, including laws and regulations relating to climate change, whether currently in force or enacted in the future. It is not currently possible to predict the nature of any future requirements, including those currently set out in Bill C-69, or the impact the future requirements will have on the company and its business, financial condition and results of operations. Suncor continues to actively work to mitigate the company's environmental impact, including taking action to reduce GHG emissions intensity, 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. Refer to the Narrative Description of Suncor's Businesses Oil Sands New Technology section of this AIF.

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 regulate, 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 GHG emissions 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

The global goal of 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 pre-industrial levels. Pursuant to the Paris Agreement, 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 developed the *Pan-Canadian Framework on Clean Growth and Climate Change* (PCF) in 2016 together with provincial (except Manitoba and Saskatchewan) and territorial leaders and in consultation with Canada's Indigenous Peoples to meet Canada's emissions target while enabling economic growth.

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.

In early 2018, the federal government released its legislative proposal for the federal carbon pricing system, entitled the *Greenhouse Gas Pollution Pricing Act* (GGPPA). The GGPPA reinforces the approach taken in the PCF and is only intended to serve as a regulatory backstop in the event a province or territory does not otherwise implement an adequate provincial or territorial GHG regime.

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 will 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 with regulations not anticipated to be enacted

until mid-2019, the company is 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, the Edmonton refinery and Syncrude are currently subject to the SGER. For the 2016 compliance year, Suncor earned a compliance credit under the SGER of $2.8 million in respect of its owned and operated properties. For the 2017 compliance year, Suncor estimates a compliance cost for all of Suncor's owned and operated assets of $12.9 million. The change year-over-year in compliance costs is due to a combination of the increase in the carbon price from $20/tonne in 2016 to $30/tonne in 2017 and a corresponding requirement for facilities in Alberta to further reduce emissions from a 15% reduction in 2016 to a 20% reduction in 2017. Fort Hills is deemed to be a 'new facility' and is exempt from compliance payments under SGER. The 2017 estimated compliance cost for Syncrude is $31.5 million, net to Suncor.

On January 1, 2018, the SGER was replaced with the *Carbon Competitiveness Incentive Regulation* (CCIR), with a three-year phase-in period. Similar to the SGER, the CCIR applies to facilities emitting more than 100,000 tonnes per annum. The CCIR is designed to incent CCIR facilities to reduce GHG emissions through improving performance by establishing product-based performance standards (also called output-based allocations) across all industries. To protect the competitiveness of trade-exposed sectors like the oil sands, the CCIR provides facilities with output-based allocation credits up to a predetermined performance benchmark. Performance benchmarks have been set for each of oil sands mining, in situ and refining operations. Facilities will pay a carbon levy based on the amount of net emissions by which they fall short of the performance benchmark and companies will receive credits based on the amount of reductions by which they exceed the benchmark. The 2018 carbon levy will remain at $30/tonne. For 2018, the estimated compliance cost for all of Suncor's owned and operated Alberta assets is $24.0 million. Emissions associated with the anticipated ramp up of Fort Hills in 2018 will remain exempt as a "new facility" under the CCIR. The 2018 estimated compliance cost for Syncrude is $24.1 million, net to Suncor.

Effective as of January 1, 2017, Alberta enacted the *Climate Leadership Implementation Act* (Climate Act). The Climate Act implements an economy-wide carbon levy on GHG emissions resulting from the combustion of fuels for heating and transportation on consumers and larger facilities on operations not otherwise subject to the SGER (and as of January 1, 2018, the CCIR).

Further, the Alberta *Oil Sands Emissions Limit Act* (the OSELA) sets a limit of 100 Mt/year in the oil sands sector, excluding emissions from cogeneration and new upgrading capacity, allowing for continued growth and development while the sector works to accelerate emissions reduction technologies and operational optimization. Current oil sands emissions are estimated to be 70 Mt/year, including existing upgrading capacity, but excluding cogenerated electricity sold to the grid. The mechanics of implementation and enforcement of the OSELA are currently under review by the Government of Alberta and it is not yet possible to predict the impact on Suncor.

The Province of British Columbia enacted a carbon tax in 2008. The tax is currently capped at $30/tonne of CO_{2e} until April 2018 when it will rise annually by $5/tonne. 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 and Ontario regulate carbon through cap-and-trade systems that 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 2016 and 2017 compliance years, the cost of compliance for the Montreal refinery was $0.1 million and $0.3 million, respectively. The 2018 forecast compliance cost attributed to the Montreal refinery's stationary emissions is $2 million. The majority of the compliance costs covering the emissions from transportation fuels are passed through to the customer. In 2017, Ontario facilities, including Suncor's Sarnia refinery, that generate more than 25,000 tonnes of GHG emissions per year are required to participate in the cap-and-trade program. For the 2017 compliance year, the cost of compliance for the Sarnia refinery was $0.1 million. In 2018, Suncor forecasts a compliance credit of $0.1 million related to facilities emissions. Similar to Quebec, costs attributed to emissions from transportation fuels are passed through to the customer.

The Government of Newfoundland and Labrador's *Management of Greenhouse Gas Act* (MGGA) requires facilities that emit 15,000 tonnes of CO_{2e} or more per annum to report their emissions. The underlying purpose of the reporting requirement is for the government to develop appropriate reduction targets to reduce provincial emissions. Large industrial emitters, which include the offshore petroleum sector, account for approximately 43% of the

province's current emissions. Newfoundland and Labrador's emissions reduction regulation is being modelled after Alberta's SGER. Similar to the Alberta SGER, the MGGA also contemplates the establishment of a fund for clean technology, through compliance payments made by industrial emitters. This is expected to support technology and innovation as well as provide flexible compliance options and protect the competitiveness of energy-intensive trade-exposed sectors. A 2018 forecast is unavailable pending the Government of Newfoundland and Labrador finalizing the policy.

U.S. GHG Regulations

The U.S. Environmental Protection Agency (U.S. EPA) has established a rule mandating that all large facilities (defined as facilities emitting greater than 25,000 tonnes of CO_{2e} per year, which includes Suncor's refinery in Commerce City, Colorado) must report their GHG emissions. The mandate of the U.S. EPA is under review by the current administration. In June 2017, the withdrawal of the U.S. from the Paris Agreement was announced. The current administration, in favour of energy and pipeline development, has also overturned a number of decisions made by the previous administration. Suncor continues to monitor these developments. The outcome of these changes in approach to GHG emissions is currently unclear and 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 management 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*, is part of Alberta's approach to managing land and natural resources to achieve long-term economic, environmental and social goals, and identifies new conservation areas as well as management frameworks to ensure the continued regional quality of air, surface water and groundwater. The conservation areas do not overlap with any of Suncor's leases. The management frameworks formalize a number of regulatory tools 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 Management Framework (AQF). The AQF 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 AQF includes ambient air quality triggers and limits. Regulatory actions will occur when triggers or limits are reached or exceeded.

Surface Water Quality Management Framework (SWF-Quality). The SWF-Quality provides a basis with which to monitor and manage long-term, cumulative changes in water quality within the Lower Athabasca River. The SWF-Quality 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 Management Framework (GMF). The GMF aims to manage non-saline groundwater resources in a sustainable manner and protect resources from contamination and over use. It 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 (SWF-Quantity). The SWF-Quantity establishes 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. Suncor and Syncrude have voluntarily agreed to minimize water withdrawals for pre-existing plant operations to half of the maximum allowable withdrawal limit, from 4 m^3/s to 2 m^3/s, during periods of low flow for the Athabasca River. The Fort Hills mining project has on-site water storage to meet the SWF-Quantity requirements during low flow.

Tailings Management Framework for Mineable Athabasca Oil Sands (TMF). The TMF 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, an updated version of which was finalized in October 2017. 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 it is not possible to predict what impact those amounts could have on Suncor.

Suncor is committed to reclaiming and remediating lands affected by its operations. In the past few years, Suncor has improved its tailings management efforts and became the first company to reclaim an oil sands tailings pond, convert a second to a fluid tailings treatment area, and make another pond trafficable with coke capping. Under the TMF, updated tailings management plans are required to be submitted for the Oil Sands Base, Syncrude and Fort Hills facilities. The updated tailings management plan for Oil Sands Base was approved in October 2017, and the updated tailings management plan for Syncrude is pending approval by the AER. The updated tailings management plan for Fort Hills is expected to be submitted in 2018. The updated tailings management plan approved for Oil Sands Base, the plan submitted for Syncrude and the plan to be submitted for Fort Hills align with the company's principles on mine, tailings and reclamation to: (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.

Another important component identified in the TMF is a need to focus on integrated water management as Suncor reclaims and liberates water from tailings. By fully considering all water management options (reduce, reuse, recycle and return) and existing policy and regulatory mechanisms, there may be additional criteria, guidelines and/or policy work required to support all aspects of an integrated approach involving successful reclamation and closure planning.

Reclamation

The Government of Alberta's MFSP accounts for the environmental liability associated with the suspension, abandonment, remediation and surface reclamation of oil sands mines and plant sites. 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 reclaim the site to a care and custody state. 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 provides early warning of any potential risks of a tailings management action, specific to the TMF. It is expected that revisions to the MFSP will be completed in 2018.

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 oil sands industry of enhanced monitoring under the Monitoring Plan have been estimated at approximately $50 million per year. The annual costs to Suncor under the Monitoring Plan are estimated to be approximately $10 million and the annual costs to Syncrude are estimated to be approximately $5.2 million (gross).

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

Suncor's financial performance is closely linked to prices for crude oil in the company's upstream business and prices for refined petroleum products in the company's downstream business and, to a lesser extent, to natural gas prices in the company's 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 the company's 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 oil and SCO.

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 by, among other things, 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 business, 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 in part 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 may 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 unfavourable differentials could have a material adverse effect on Suncor's business, financial condition and reserves.

Beginning in the latter half of 2014, world oil prices declined significantly. While oil prices have moderately recovered from the low prices that were experienced during that time, due in part to quotas agreed upon 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 establish new quotas, or to meet or maintain agreed upon quotas, or increases in supply from other countries (including Canada and the U.S.), 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 and 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.

In general, Suncor's operations are subject to operational hazards and risks such as, among others, fires (including forest fires), explosions, blow-outs, power outages, severe winter climate conditions, prolonged periods of extreme cold or extreme heat, flooding, droughts 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, among other things, 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, among others, the following:

- Suncor's Oil Sands business is susceptible to loss of production, slowdowns, shutdowns or restrictions on its 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 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 facilities or operations, or result in a shortage of appropriate equipment or specialists required to perform planned operations; and

- Suncor's Refining and Marketing operations are subject to all of the risks normally inherent in the operation of refineries, terminals, pipelines and other distribution facilities and service stations, including, among others, loss of production, slowdowns or shutdowns 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 the company's 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, reserves and results of operations. Refer also to Statement of Reserves Data and Other Oil and Gas Information Significant Risk Factors and Uncertainties Affecting Reserves.

Government/Regulatory Policy and Effectiveness

Suncor's businesses operate under federal, provincial, territorial, state and municipal laws in numerous countries. The company, including its joint arrangements, is also subject to regulation and intervention by governments in oil and gas industry matters, such as, among others, land tenure, royalties, taxes (including income taxes), government fees, production rates, environmental protection, wildlife, fish, safety performance, the reduction of GHG and other emissions, the export of crude oil, natural gas and other products, 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, reclamation and abandonment of fields and mine sites (including restrictions on production), mine financial security requirements and possibly expropriation or cancellation of contract rights. As part of ongoing operations, the company, including its joint arrangements, 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 applicable laws and regulations may result in, among other things, the imposition of fines and penalties, production constraints, a compulsory shutdown of facilities or suspension of operations, reputational damage, delays, increased costs, denial of operating and growth permit applications, censure, liability for cleanup costs and damages, and the loss of important licences and permits.

Before proceeding with most major projects, including significant changes to existing operations, Suncor, including its joint arrangements, must obtain various federal, provincial, territorial, state and municipal permits and regulatory approvals, and 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's businesses 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.

Failure to obtain, comply with, satisfy the conditions of 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 and results of operations.

Changes in government policy (including, among others, trade policies affecting energy resource exports and increased regulation as a result of climate change), regulation or other laws, 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, or which makes current operations or growth projects uneconomic could materially impact Suncor's operations, existing and planned projects, financial condition, reserves and results of operations. Obtaining necessary approvals or permits has become more difficult due to increased public opposition and consultation, including Aboriginal consultation requirements as well as increased political involvement. The federal government also issued Bill C-69 in February 2018. If enacted, it will impact the manner in which large energy projects are approved, including increased Aboriginal consultation and involvement. 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 and results of operations. Refer to the Industry Conditions section of this AIF.

Carbon Risk

Public support for climate change action and receptivity to alternative/renewable energy 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 in general, and in the oil sands industry in particular.

Environmental regulation, including regulation relating to climate change, could impact the demand for, formulation or quality of the company's products, or could require increased capital expenditures, operating expenses and distribution costs, which may or may not be recoverable in the marketplace and which may result in current operations or growth projects becoming uneconomic. In addition, such regulatory changes could necessitate that Suncor develop new technologies. Such technology development could require a significant investment of capital and resources, and any delay in or failure to identify and develop such technologies could prevent Suncor, including its joint arrangements, 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 continues its efforts to reduce the intensity of its GHG emissions, the absolute GHG emissions of the company are expected to rise as it pursues a growth strategy. Increases in GHG emissions may impact the profitability of the company's 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 and results of operations.

Environmental Compliance

Tailings Management

There are risks associated with Suncor's tailings management plans, including those of its joint arrangements. 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, or if any conditions to the approval for the plans are not satisfied, 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, including those of its joint arrangements, 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 and results of operations.

Alberta's Land-Use Framework (LARP)

The implementation of, and compliance with, the terms of the LARP may adversely impact Suncor's 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 uncertainty of changes in Suncor's future development and existing operations required as a result of the LARP could have an adverse effect on Suncor's business, financial condition, reserves and results of operations.

Alberta Environment and Parks (AEP) Water Licences

Suncor currently relies on water obtained under licences from AEP to provide domestic and utility water for the company's Oil Sands business. 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 and results of operations.

Species at Risk Act

Woodland caribou have been identified as Threatened under the *Species at Risk Act* (Canada). In response to the Government of Canada's Recovery Strategy for Woodland Caribou, provincial caribou range plans are being developed. Suncor has existing, planned and potential future projects within caribou ranges in Alberta. The development and implementation of range plans in these areas may have an impact on the pace and amount of development in these areas and could potentially increase costs for restoration or offsetting requirements, which could have a material adverse effect on Suncor's business, financial condition, reserves and results of operations.

Air Quality Management

A number of Canadian federal and provincial air quality regulations and frameworks are currently being developed, changed and/or implemented, which could have an impact on the company's existing and planned projects by requiring the company to invest additional capital or incur additional operating and compliance expenses, including, among other things, potentially requiring the company to retrofit equipment to meet new requirements and increase monitoring and mitigation plans. The full impact of these regulations and frameworks is not yet known; however, they could have a material adverse effect on Suncor's business, financial condition, reserves and results of operations.

Alberta Wetland Policy

Pursuant to the Alberta Wetland Policy, development in wetland areas may be required to avoid wetlands or mitigate the development's effects on wetlands. Although the full impact of the policy on Suncor is not yet fully known, certain of Suncor's operations and growth projects may be affected by aspects of the policy where avoidance is not possible and wetland reclamation or replacement may be required, which could have a material adverse effect on Suncor's business, financial condition, reserves and results of operations.

Market Access

Suncor's production of bitumen is expected to grow as production ramps up at 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 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. The occurrence of any of the foregoing could have a material adverse effect on the company's business, financial condition, reserves and results of operations.

Information Security

The efficient operation of Suncor's business is dependent on computer hardware, software and networked 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 the company's employees and retail customers. Suncor's operations are also dependent upon a large and complex information framework. Suncor relies on industry accepted security measures, controls and technology to protect Suncor's information systems and securely maintain confidential and proprietary information stored on the company's information systems, and has 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 Audit Committee of the Board of Directors. However, the measures, controls and technology on which the company relies 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 malicious persons or entities 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 and results of operations. Although the company maintains a risk management program, which includes an insurance component that may provide coverage for the operational impacts from an attack to, or breach of, Suncor's information technology and infrastructure, including process control systems, the company does not maintain stand-alone cyber insurance. Furthermore, not all cyber risks are insurable. As a result, Suncor's existing insurance may not provide adequate coverage for losses stemming from a cyber attack to, or breach of, its information technology and infrastructure.

Project Execution

There are certain risks associated with the execution of Suncor's major projects and the commissioning and integration of new facilities within its 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, among other things:

- Failure to comply with Suncor's Asset Development 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;

The ability to obtain the necessary environmental and other regulatory approvals;

The impact of general economic, business and market conditions and the company's 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;

Complexities and risks associated with constructing projects within operating environments and confined construction areas;

The complexities and uncertainties associated with identification, development and integration of new technologies into the company's existing and new assets;

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;

The company's ability to complete strategic transactions; and

The commissioning and integration of new facilities within the company's 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 and results of operations.

Cumulative Impact of Change

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 and results of operations.

Joint Arrangement Risk

Suncor has entered into joint arrangements and other contractual arrangements with third parties, including arrangements where other entities operate assets in which Suncor has ownership or other interests. These joint arrangements include, among 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 activities relating to 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, among others, 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 the company's participation in the operation of such assets or in the development of such projects, the company's 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, funding 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 and results of operations.

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 the company unable to liquidate or offset a position, or unable to do so at or near the previous market price;

The company may not receive funds or instruments from counterparties at the expected time or at all;

The counterparty could fail to perform an obligation owed to Suncor;

Loss as a result of human error or deficiency in the company's 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 and results of operations.

Exchange Rate Fluctuations

The company's 2017 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 denominated 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 therefore, 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, 2017, the Canadian dollar strengthened in relation to the U.S. dollar to 0.80 from 0.74 at the start of 2017. Exchange rate fluctuations could have a material adverse effect on Suncor's business, financial condition, reserves and results of operations.

Interest Rate Risk

The company is 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 and money market instruments. Suncor is also exposed to interest rate risk when debt instruments are maturing and require refinancing, or when new debt capital needs to be raised. The company is 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, reserves and results of operations.

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 financial institutions and investor appetite for investments in the energy industry generally, and the company's securities in particular. To the extent that external sources of capital become limited or unavailable or available on unfavourable terms, the ability to make capital investments and maintain existing properties may be constrained.

If the company finances capital expenditures in whole or in part with debt, that may increase its debt levels above industry standards for oil and gas companies of similar size. Depending on future development plans, additional debt financing may be required 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 may be incurred; however, Suncor is subject to covenants in its existing bank facilities and seeks to avoid an unfavourable cost of debt. The level of the company's indebtedness, from time to time, could impair its ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise and could negatively affect its credit ratings.

Suncor is required to comply with financial and operating covenants under existing credit facilities and debt securities. Covenants are reviewed based on actual and forecast results and the company has the ability to make changes to its 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, including its subsidiaries. Their ratings of Suncor's long-term and short-term debt are based on a number of factors, including the company's financial strength, as well as factors not entirely within its 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 Suncor competes in certain markets and when it seeks to engage in certain transactions, including transactions involving over-the-counter derivatives. There is a risk that one or more of Suncor's credit ratings could be downgraded, which could potentially limit its 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 and results of operations.

Third-Party Service Providers

Suncor's businesses are 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 and jointly owned 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 the company's 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 the company's 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 and results of operations.

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 and results of operations.

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, reserves and results of operations.

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, test or pilot 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 or comply with regulatory requirements, which could have a material adverse effect on Suncor's business, financial condition, reserves and results of operations.

Skills, Resource Shortage and Reliance on Key Personnel

The successful operation of Suncor's businesses and the company's ability to expand operations will depend upon the availability of, and competition for, skilled labour and materials supply. There is a risk that the company 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 the company's existing workforce adds further pressure. Materials may also be in short supply due to smaller labour forces in many manufacturing operations. Suncor's ability to operate safely and effectively and complete all projects on time and on budget has the potential to be significantly impacted by these risks and this impact could be material.

The company's 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 Suncor's Oil Sands operations facilities, all of the company's refineries, certain of the company's terminal and distribution operations, and the Terra Nova FPSO are represented by labour unions or employee associations. Approximately 38% of the company's employees were covered by collective agreements at the end of 2017. Negotiations for a new collective agreement are in progress with the Teamsters Canada union at Suncor's Burrard terminal and with Unifor at the company's ETFD. Any work interruptions involving the company's employees (including as a result of the failure to successfully negotiate new collective agreements with unions), contract trades utilized in the company's 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 and results of operations.

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. Suncor competes in virtually every aspect of its business with other energy companies. The petroleum industry also competes with other industries in supplying energy, fuel and related products to consumers. The increasing volatility of the political and social landscape at provincial, federal, territorial, state, municipal and international levels adds complexity.

For Suncor's Oil Sands business, 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 the company's 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 and results

of operations.

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 the company's business.

The requirement to consult with Aboriginal Peoples in respect of oil and gas projects and related infrastructure has also increased in recent years and will further increase under Bill C-69. In addition, the Canadian federal government and the provincial government in Alberta have made a commitment to renew their relationships with the 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." Recently, the federal government announced its support of a private member's bill, Bill C-262, *An Act to ensure that the laws of Canada are in harmony with the United Nations Declaration on the Rights of Indigenous Peoples*, promoting the full adoption of the Declaration into Canadian law. It is anticipated that the Bill may become law in 2018. 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.

Suncor is unable to assess the effect, if any, that any such land claims, consultation requirements with Aboriginal Peoples or adoption of the Declaration into Canadian law may have on Suncor's business; however, the impact may be material.

Litigation Risk

There is a risk that Suncor or entities in which it has an interest 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, climate change and the impacts thereof, breach of contract, product liability, antitrust, bribery and other forms of corruption, tax, patent infringement, employment matters and in relation to an attack, breach or unauthorized access to Suncor's information technology and infrastructure. 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 to the company and/or the company may be required to incur significant expenses or devote significant resources in defence against such litigation, the success of which cannot be guaranteed.

Dividends

Suncor's payment of future dividends on its common shares will be dependent on, among other things, legislative requirements, the company's financial condition, results of operations, cash flow, 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 and results of operations.

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. The Board approved a dividend of $0.28 per common share in the first and second quarters of 2015 and a dividend of $0.29 per common share in the third and fourth quarters of 2015. The Board approved a quarterly dividend of $0.29 per common share in each quarter of 2016 and a quarterly dividend of $0.32 per common share in each quarter of 2017. Dividends are paid subject to applicable law, if, as and when declared by the Board.

Year ended December 31	**2017**	2016	2015
Cash dividends per common share ($)	**1.28**	1.16	1.14

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, 2017, there were 1,640,983,359 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 for Suncor Energy Inc. by the rating agencies noted herein as of February 28, 2018. 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[(1)]	Outlook	Canadian Commercial Paper Program	U.S. Commercial Paper Program
Standard & Poor's (S&P)	A-	Stable	A-1 (low)	A-2
Dominion Bond Rating Service (DBRS)	A (low)	Stable	R-1 (low)	Not rated
Moody's Investors Service (Moody's)	Baa1	Stable	Not rated	P-2

(1) The Senior Unsecured debt of Suncor Energy Ventures Corporation, a wholly owned subsidiary of Suncor, which indirectly owns a 36.74% ownership in the Syncrude joint operation previously owned by COS (refer to Intercorporate Relationships), is rated A- (Stable) by S&P and Ba3 (Stable) by Moody's. DBRS does not issue a separate credit rating for Suncor Energy Ventures Corporation.

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. A rating of Ba by Moody's is the fifth highest of nine categories. Obligations rated Ba are judged to be speculative and are subject to substantial credit risk. 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

Suncor's 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, 2017 are as follows:

TSX

	Price Range (Cdn$)		Trading Volume
	High	Low	(000s)
2017			
January	44.90	40.00	53 343
February	42.95	39.70	56 407
March	42.28	39.65	73 249
April	42.94	40.23	41 944
May	44.19	41.10	56 822
June	42.67	37.72	66 953
July	40.93	36.09	46 741
August	41.91	38.34	48 696
September	43.88	38.88	60 103
October	44.19	41.88	56 855
November	46.66	43.90	47 943
December	46.27	43.45	47 581

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 2017 audited Consolidated Financial Statements, which is incorporated by reference into this AIF and available on SEDAR at www.sedar.com.

On November 15, 2017, Suncor issued an aggregate of US$750 million 4.00% senior unsecured notes due in 2047.

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, U.S.	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 & 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] Quebec, 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 CHU Sainte-Justine Foundation. 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's degree in 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, U.S.	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.

Dennis Houston Texas, U.S.	Director since 2018 Independent	Dennis Houston served as executive vice president of ExxonMobil Refining & Supply Company, Chairman and President of ExxonMobil Sales & Supply LLC and Chairman of Standard Tankers Bahamas Limited until his retirement in 2010. Prior to that, Mr. Houston held a variety of leadership and engineering roles in the midstream and downstream businesses in the ExxonMobil organization. Mr. Houston has approximately 40 years' experience in the oil and gas industry, including over 35 years with ExxonMobil and its related companies. Mr. Houston serves on the board of directors of Argus Media Limited and GasLog Ltd. Mr. Houston holds a bachelor's degree in chemical engineering from the University of Illinois and an Honorary Doctorate of Public Administration Degree from Massachusetts Maritime Academy. Mr. Houston has served on a variety of advisory councils including an appointment by President George H.W. Bush to the National Infrastructure Advisory Council, the Chemical Sciences Leadership Council at the University of Illinois and the Advisory Council Center for Energy, Marine Transportation & Public Policy at Columbia University. Mr. Houston also serves on the Alexander S. Onassis Public Benefit Foundation Board, is Honorary Consul to the Texas Region for the Principality of Liechtenstein and a board member for the American Bureau of Shipping Group of Companies.
John R. Huff[1][2][5] Texas, U.S.	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, Canada's largest privately held market research firm and formerly president of Criterion Research, a company she founded in 1986. Ms. McCaw is chair of the CBC Pension Fund Plan board of trustees and is a director of the Canadian Broadcasting Corporation and Francis Winspear/Edmonton Symphony. She also serves on a number of other boards and advisory committees, including as co-chair of Women United (Edmonton). Ms. McCaw is past chair of the Edmonton International Airport and 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][5] 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.
Eira M. Thomas[1][2] B.C., Canada	Director since 2006 Independent	Eira Thomas is a Canadian geologist with over 20 years of experience in the Canadian diamond business. She is currently the chief executive officer and a director of Lucara Diamond Corp., a publically traded diamond producing company. Previous roles include serving as chief executive officer and a director of Kaminak Gold Corporation, vice president of Aber Resources, now Dominion Diamond Corp., and as founder and CEO of Stornoway Diamond Corp.

Steven W. Williams Alberta, Canada	Director since December 2011 Non-independent, management	Steve Williams is president and chief executive officer of Suncor. His career with Suncor began in May 2002 when he joined the company as executive vice president, corporate development and chief financial officer. He has also served as executive vice president, oil sands and chief operating officer. Mr. Williams has more than 40 years of international energy industry experience, including 18 years at Esso/Exxon. Mr. Williams holds a bachelor's 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. In 2016, Mr. Williams was named to the board of directors of the new Alcoa Corporation. Mr. Williams is a board member of the Business Council of Canada and is a member of the Institute of Corporate Directors and the National Association of Corporate Directors. He is an active supporter of not-for-profit organizations. Mr. Williams has long been an advocate for sustainable development in the energy industry and is a leader in conversations that connect the environment and economy. In 2005 he was appointed to the National Roundtable on the Environment and the Economy by the Prime Minister of Canada. He has also been a member of the advisory board of Canada's Ecofiscal Commission since its inception. He is one of 12 founding CEOs of COSIA and he was invited to attend the 2015 United Nations Climate Change Conference (COP21) in Paris, France as an official member of the Government of Canada delegation.
Michael M. Wilson Alberta, Canada	Director since 2014 Independent	Michael Wilson is former president and chief executive officer of Agrium Inc., a retail supplier of agricultural products and services and a wholesale producer and marketer of agricultural nutrients, a position he held from 2003 until his retirement in 2013. Prior thereto, he 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 and Celestica Inc.

(1) Human Resources and Compensation Committee

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

(3) Audit Committee

(4) Governance Committee

(5) Messrs. Huff and O'Brien will retire from the Board of Directors at the conclusion of Suncor's 2018 annual meeting of shareholders.

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	Chief Operating Officer
Eric Axford	Alberta, Canada	Executive Vice President and Chief Sustainability Officer
Alister Cowan	Alberta, Canada	Executive Vice President and Chief Financial Officer
Mike MacSween	Alberta, Canada	Executive Vice President, Upstream
Steve Reynish	Alberta, Canada	Executive Vice President, Strategy & Operations Services
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 23, 2018, the directors and executive officers of Suncor as a group beneficially owned, or controlled or directed, directly or indirectly, 817,382 common shares of Suncor, which represents 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 the capacity as director, chief executive officer, or chief financial officer; 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, or any of their respective personal holding companies, 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 Ms. Bedient (Chair), Ms. Côté, Mr. D'Alessandro, Ms. McCaw and Mr. O'Brien. All members are independent and financially literate. The education and experience 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 Ms. Bedient, Mr. D'Alessandro and Mr. O'Brien.

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

Suncor's Audit Committee has considered whether the provision of services other than audit services is compatible with maintaining the company's auditors' independence and has a policy governing the provision of these services. A copy of the company's policy relating to Audit Committee approval of fees paid to the company's 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)	**2017**	2016
Audit Fees	**5 254**	5 758
Audit-Related Fees	**415**	415
Tax Fees		15
All Other Fees	**15**	25
Total	**5 684**	6 213

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 Suncor is or was a party, or in respect of which any of the company's property is or was the subject during the year ended December 31, 2017, nor are there any such proceedings known by the company to be contemplated, that involve a claim for damages exceeding 10% of the company's 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, 2017, (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, 2017.

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 Suncor's common shares is Computershare Trust Company of Canada at its principal offices in Calgary, Alberta, Montreal, Quebec, Toronto, Ontario and Vancouver, B.C., Computershare Trust Company Inc. in New York, New York and Computershare Trust Company N.A. in Golden, Colorado.

MATERIAL CONTRACTS

During the year ended December 31, 2017, Suncor did not enter into any contracts, nor are there any contracts still in effect, that are material to the company's 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 Suncor's outstanding securities, including the securities of the company's 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, 2018 in respect of the company's Consolidated Financial Statements, which comprise the Consolidated Balance Sheets as at December 31, 2017 and December 31, 2016 and the Consolidated Statements of Comprehensive Income (Loss), Changes in Equity and Cash Flows for the years ended December 31, 2017 and December 31, 2016, and the related notes, and the report on internal control over financial reporting as at December 31, 2017. 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, Suncor is not required to comply with most of the NYSE's rules and instead may comply with Canadian requirements. As a foreign private issuer, the company is 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 the company's 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 2018 management proxy circular, which is available on Suncor's website at www.suncor.com, significant areas in 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 Suncor's securities, and securities authorized for issuance under equity compensation plans, where applicable, is contained in the company's most recent management proxy circular for the most recent annual meeting of shareholders that involved the election of directors. Additional financial information is provided in Suncor's 2017 audited Consolidated Financial Statements for the company's 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, Suncor's Standards of Business Conduct Code is available online at www.suncor.com. Information contained in or otherwise accessible through the company's 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; future production rates; the sufficiency of budgeted capital expenditures in carrying out planned activities; the availability and cost of labour, services and infrastructure; the satisfaction by third parties of their obligations to Suncor; the execution of projects; and the receipt, in a timely manner, of regulatory and third-party approvals. All statements and information that address expectations or projections about the future, and 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", "forecast" and similar expressions.

Forward-looking statements in this AIF include references to:

Suncor's strategy, business plans and expectations about the cost and development of projects, the performance, of assets, production volumes, and capital expenditures, including:

- *Expectations about Fort Hills, including the project's gross nameplate capacity of 194 mbbls/d of bitumen (104 mbbls/d net to Suncor), the expectation that testing of the front end of the plant during the fourth quarter of 2017 will mitigate the risk associated with the ramp up in 2018, the expectation that the second and third trains of secondary extraction will start up in the first half of 2018, and the expectation that the project will reach 90% capacity by the end of 2018;*

- *Expectations about Hebron, including the expectation that, at peak, the project will produce more than 30,000 bbls/d (net to Suncor) and will ramp up over the next several years, and the expectation that drilling activities will continue throughout 2018;*

- *Expectations about Syncrude, including the expectation that the Syncrude co-owners' plan to develop MLX-W and MLX-E would extend the life of Mildred Lake by a minimum of 10 years, the expectation that the MLX-E program will follow MLX-W development, the expectation that the MLX-W program will sustain bitumen production levels at the Mildred Lake site after resource depletion at the North Mine, plans for MLX-W and the expectation that the AER will respond in the second quarter of 2018, the expectation that sanctioning of MLX-W will occur in late 2019 or early 2020, the opportunity for cost management and collaboration between the company and Syncrude that involves exploring the option, subject to approval by Syncrude co-owners, for pipelines connecting Syncrude and Oil Sands Base, and the expectation that sustaining capital expenditures in 2018 will focus on a planned turnaround and capacity maintenance;*

- *Expectations about the Rosebank project, including its anticipated gross 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, and that it is expected to be complementary to Suncor's existing U.K. portfolio;*

- *Expectations about the West White Rose project, including the expectation that it will extend the life of the existing White Rose assets, the company's estimated share of peak oil production of 20,000 bbls/d, the expectation that major development activity will begin in 2018, and that first oil is targeted for 2022;*

- *Expectations about the Meadow Creek East and West projects, including that they are part of the company's planned in situ replication strategy, the expectation that the Meadow Creek East project will be developed in stages, anticipated production from the Meadow Creek East project of 40 mbbls/d up to 80 mbbls/d, the expectation that construction of the Meadow Creek East project could be begin as early as 2020 with first oil expected as early as 2023, anticipated production from the Meadow Creek West project of 40 mbbls/d, and the expectation that construction of the Meadow Creek West project will begin in 2022 with first oil expected in 2025;*

Expectations 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) in the second half of 2019, and that Suncor's share of the post-sanction project cost estimate is approximately $270 million;

Expectations about the Fenja development project, including the expectation that the plan for development and operation will be approved by the Ministry of Petroleum and Energy in the first half of 2018, the plan

for development, first oil planned for 2021, the expectation that peak production will be 34 mbbls/d (6 mbbls/d net to Suncor) and will be reached between 2021 and 2022, and Suncor's share of the post-sanction project cost estimate of approximately $280 million;

Expectations about the closing of the transactions with Canbriam and Faroe Petroleum and the timing thereof;

The estimated cost of Suncor's remaining exploration work program commitment in Libya at December 31, 2017 of US$359 million;

Potential future wind and solar power projects;

The potential for future in situ production to be supported at Meadow Creek, Lewis, OSLO and Chard and for exploratory or delineation drilling at Kirby and drilling plans at Terra Nova; and

The expectation that capital investments at Oil Sands Base and Syncrude will maintain the production capacity of existing facilities and that the drilling of new well pairs and infill wells, as well as the design and construction of new well pads, at Firebag and MacKay River will maintain production levels in future years.

Also:

Expectations and goals around technologies, including 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 2018, 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, issuing commercial paper and, if needed, the divestiture of non-core assets and accessing capital markets will be sufficient to fund future development costs and that interest expense or other funding costs on their own would not make development of any property uneconomic, plans for the development of reserves, and the estimated value of work commitments;

Estimated abandonment and reclamations costs;

The company's commitment to continuously optimize its asset portfolio and focus on core assets and ongoing balance sheet flexibility from the reduction of debt;

Expectations about royalties and income taxes and their impact on Suncor;

Expectations regarding tailings management plans and regulatory processes with respect thereto;

Anticipated effects of and responses to environmental laws, including climate change laws, and Suncor's estimated compliance costs; and

Expectations about changes to laws and the impact thereof.

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 Suncor's 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 the company's proprietary production will be closed, experience equipment failure or other accidents; Suncor's ability to operate its 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; Suncor's dependence on pipeline capacity and other logistical constraints, which may affect the company's ability to distribute products to market; Suncor's 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; changes in operating costs, including the cost of labour, natural gas and other energy sources used in oil sands processes; and the company's 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).

Factors that affect Suncor's 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 market demand for mineral rights and producing properties, potentially leading to losses on disposition or increased property acquisition costs.

Factors that affect Suncor's 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; the company's 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; and 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.

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; risks associated with the execution of Suncor's major projects and the commissioning and integration of new facilities; 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 to laws and government policies that could impact the company's business, including environmental (including climate change), royalty and tax laws and policies; the ability and willingness of parties with whom Suncor has material relationships to perform their obligations to the company; the unavailability of, or outages to, third-party infrastructure that could cause disruptions to production or prevent the company from being able to transport its products; the occurrence of a protracted operational outage, a major safety or environmental incident, or 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 malicious persons or entities, and the unavailability or failure of such systems to perform as anticipated as a result of such breaches; the risk that competing business objectives may exceed Suncor's capacity to adopt and implement change; risks and uncertainties associated with obtaining regulatory and stakeholder approval for the company's operations and exploration and development activities; the potential for disruptions to operations and construction projects as a result of Suncor's relationships with labour unions that represent employees at the company's facilities; the company's 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 or to issue other securities at acceptable prices; 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 relating to increased activism and public opposition to fossil fuels and oil sands; 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; risks associated with joint arrangements in which the company has an interest; the receipt of any required regulatory or other third-party approvals outside of Suncor's control and the satisfaction of any conditions to such approvals; risks associated with land claims and Aboriginal consultation requirements; risks relating to litigation; the impact of technology and risks associated with developing and implementing new technologies; 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, 2018 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 financial measure that is not prescribed by GAAP. Non-GAAP measures do not have any standardized meaning and therefore are unlikely to be comparable to similiar 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. 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, 2017 and dated March 1, 2018.

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 and they may be useful to investors for the same reason.

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 and they may be useful to investors for the same reason.

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 by:

- monitoring the effectiveness and integrity of the Corporation's internal controls of Suncor's business processes, including: financial and management reporting systems, 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 audits conducted of the Corporation's Standards of Business Conduct-Compliance Program.
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. Approve the appointment or termination of the VP Enterprise Risk and Audit, approve annually the performance assessment and resulting compensation of the VP Enterprise Risk & Audit as provided by the Chief Financial Officer. Periodically review the performance and effectiveness of the Internal Audit function including conformance with The Institute of Internal Auditors' International Standards for the Professional Practice of Internal Auditing and the Code of Ethics.

12. Approve the Internal Audit Department Charter, the annual Internal Audit schedule, as well as the Internal Audit budget and resource plan. Review the plans, activities, organizational structure, resource capacity 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, 2017

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, 2017. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2017, 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, 2017, and identifies the respective portions thereof that we have evaluated and reported on to the Company's management and board of directors:

			Net Present Value of Future Net Revenue (before income taxes, 10% discount rate, $ millions)			
Independent Qualified Reserves Evaluator	Effective Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Audited	Evaluated	Reviewed	Total
GLJ Petroleum Consultants Ltd.	December 31, 2017	Oil Sands In Situ, Canada		24 284		24 284
GLJ Petroleum Consultants Ltd.	December 31, 2017	Oil Sands Mining, Canada		31 007		31 007
				55 291		55 291

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, 2018

"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, 2017. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2017, 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, 2017, and identifies the respective portions thereof that we have evaluated and reported on to the Company's management and board of directors:

			Net Present Value of Future Net Revenue (before income taxes, 10% discount rate, $ millions)			
Independent Qualified Reserves Evaluator	Effective Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Audited	Evaluated	Reviewed	Total
Sproule Associates Limited	December 31, 2017	East Coast Canada, Newfoundland Offshore, Canada		6 090		6 090
Sproule Associates Limited	December 31, 2017	North America Onshore, Western Canada		17		17
Sproule International Limited	December 31, 2017	North Sea, United Kingdom		3 094		3 094
Sproule International Limited	December 31, 2017	North Sea, Norway		322		322
				9 523		9 523

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, 2018

"Cameron P. Six"

Cameron P. Six, P.Eng.
President and CEO

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
Chief Operating Officer

"*Michael M. Wilson*"

MICHAEL M. WILSON
Chair of the Board of Directors

"*Patricia M. Bedient*"

PATRICIA M. BEDIENT
Chair of the Audit Committee

March 1, 2018

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 pages 65 and 66 of Exhibit 99-2.

ATTESTATION REPORT OF THE REGISTERED PUBLIC ACCOUNTING FIRM

See pages 79 and 80 of Exhibit 99-1.

AUDIT COMMITTEE FINANCIAL EXPERT

See pages 75 and 76 of Annual Information Form.

CODE OF ETHICS

See pages 24 and 25 of Annual Information Form.

FEES PAID TO PRINCIPAL ACCOUNTANT

See page 76 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 75 of Annual Information Form.

EXHIBIT INDEX

Exhibit No.	Description
99-1	Audited Consolidated Financial Statements of Suncor Energy Inc. for the fiscal year ended December 31, 2017
99-2	Management's Discussion and Analysis for the fiscal year ended December 31, 2017, dated March 1, 2018
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
101	Interactive data files with respect to the Annual Consolidated Financial Statements of Suncor Energy Inc. for the fiscal year ended December 31, 2017

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.

DATE: March 1, 2018

SUNCOR ENERGY INC.

PER: /s/ ALISTER COWAN

Alister Cowan
Executive Vice President and Chief Financial Officer

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