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UNITED STATES
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, 2019
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.
P.O. Box 2844
Calgary, Alberta, Canada T2P 3E3
(403) 296-8000

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

CT Corporation System
28 Liberty St.
New York, New York 10005
(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:	Trading Symbol(s):	Name of each exchange on which registered:
Common shares	**SU**	**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, 2019 there were 1,531,873,743 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 every Interactive Data File required to be submitted 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 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 February 26, 2020, 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, 2019, 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- 225338).

SUNCOR

ANNUAL INFORMATION FORM

Dated February 26, 2020

Suncor Energy Inc.



ANNUAL INFORMATION FORM DATED FEBRUARY 26, 2020

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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 (including those identified in Note 27 of the company's 2019 audited Consolidated Financial Statements), 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. Libyan production volumes are presented on an economic basis.

References to the 2019 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 thereto and the auditor's report thereon, as at and for each year in the two-year period ended December 31, 2019. References to the MD&A mean Suncor's Management's Discussion and Analysis, dated February 26, 2020.

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

Crude oil is a mixture, consisting mainly of pentanes and heavier hydrocarbons, that exists in the liquid phase in reservoirs and remains liquid at atmospheric pressure and temperature. Crude oil may contain small amounts of sulphur and other non-hydrocarbons, but does not include liquids obtained in the processing of natural gas.

> **Bitumen** is a naturally occurring solid or semi-solid hydrocarbon, consisting mainly of heavier hydrocarbons that are too heavy or thick to flow or be pumped without being diluted or heated, and that is not primarily recoverable at economic rates through a well without the implementation of enhanced recovery methods. After it is extracted, bitumen may be upgraded into crude oil and other petroleum products.
>
> **Light crude oil** is crude oil with a relative density greater than 31.1 degrees API gravity.
>
> **Medium crude oil** is crude oil with a relative density greater than 22.3 degrees API gravity and less than or equal to 31.1 degrees API gravity.
>
> **Heavy crude oil** is crude oil with a relative density greater than 10.0 degrees API gravity and less than or equal to 22.3 degrees API gravity.
>
> **Synthetic crude oil (SCO)** is a mixture of liquid hydrocarbons derived by upgrading bitumen and may contain sulphur or other non-hydrogen 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 mixture of lighter hydrocarbons that exist either in the gaseous phase or in solution in crude oil in reservoirs but are gaseous at atmospheric conditions. Natural gas may contain sulphur or other non-hydrocarbon compounds.

> **Conventional natural gas** is natural gas that occurs in a normal, porous, permeable reservoir rock and that, at a particular time, can be technically and economically produced using normal production practices.

Natural gas liquids (NGLs) are hydrocarbon components that can be recovered from natural gas as liquids, including, but not limited to, ethane, propane, butanes, pentanes plus, condensate, and small quantities of non-hydrocarbons. **Liquefied petroleum gas (LPG)** 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 deposits of sand, sandstone or other sedimentary rocks that contain crude bitumen.

Reservoir is a subsurface rock unit that contains a potentially recoverable 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 to define the extent of known accumulations of petroleum for the assignment of reserves. This includes wells drilled for the purpose of assessing the stratigraphy, structure and bitumen saturation of an oil sands lease.
>
> **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. The fluid is pumped into a subsurface formation sealed off from other formations by impervious strata of rock. 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 with the intention of discovering commercial reservoirs or deposits of crude oil and/or natural gas.

Infill wells are drilled within a known accumulation of petroleum, 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, or observation wells.

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 oil sands other than by 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 paraffin is used, which provides the capability to selectively remove some of the asphaltines (the highest carbon component of the barrel) from the final product. This results in a lower carbon, higher quality bitumen that can be sold directly to market without further upgrading.

Production sharing contracts (PSCs) 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-assisted gravity drainage (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 heat the bitumen. 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.

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
GWh	Gigawatt hours
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

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

Intercorporate Relationships

Material subsidiaries, each of which is wholly owned, either directly or indirectly, by the company as at December 31, 2019, are shown below:

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 the upstream Canadian businesses is marketed. This subsidiary also administers Suncor's energy trading activities and power business, markets certain third-party products, procures crude oil feedstock and natural gas for its downstream business, and procures and markets natural gas liquids (NGLs) and liquefied petroleum gas (LPG) for its 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	A subsidiary which 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 the company's U.S. refining and marketing operations are conducted.
International operations		
Suncor Energy UK Limited	U.K.	A subsidiary through which the majority of the company's North Sea operations are conducted.

The company's remaining subsidiaries each accounted for (i) less than 10% of the company's consolidated assets as at December 31, 2019, and (ii) less than 10% of the company's consolidated operating revenues for the fiscal year ended December 31, 2019. In aggregate, the remaining subsidiaries accounted for less than 20% of the company's consolidated assets as at December 31, 2019, and less than 20% of the company's consolidated operating revenues for the fiscal year ended December 31, 2019.

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 in Canada and internationally; the company transports and refines crude oil, and markets petroleum and petrochemical products primarily in Canada. Suncor also operates a renewable energy business and conducts energy trading activities focused principally on the marketing and trading of crude oil, natural gas, byproducts, refined products, and power.

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. Bitumen is either upgraded into SCO for refinery feedstock and diesel fuel, or blended with diluent for direct sale to market through the company's midstream infrastructure and its marketing activities. The Oil Sands segment includes:

- **Oil Sands operations** refer to Suncor's owned and operated mining, extraction, upgrading, in situ and related logistics, blending 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, energy, reclamation and storage facilities.
    - **In Situ** operations include oil sands bitumen production from Firebag and MacKay River and supporting infrastructure, including central processing facilities, cogeneration units, product transportation infrastructure, diluent import capabilities, storage assets and a cooling and blending facility. In Situ also includes development opportunities which may support future in situ production, including Meadow Creek (75%), Lewis (100%), OSLO (77.78%), various interests in Chard (25% to 50%), and a non-operated interest in Kirby (10%). In Situ production is either upgraded by Oil Sands Base, or blended with diluent and marketed directly to customers.
- **Fort Hills** includes Suncor's 54.11% interest in Fort Hills, which the company operates, and the East Tank Farm Development (ETFD) in which Suncor holds a 51% interest and operates.
- **Syncrude** refers to Suncor's 58.74% non-operated interest in the oil sands mining and upgrading operation.

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 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, the company holds interests in several exploration licences and significant discovery licences offshore Newfoundland and Labrador. Previously, E&P Canada also included Suncor's 37% equity interest in Canbriam Energy Inc. (Canbriam) which was sold during the second quarter of 2019.
- **E&P International** operations include Suncor's non-operated interests in Buzzard (29.89%), the Golden Eagle Area Development (GEAD) (26.69%), Oda (30%), the Fenja project (17.5%), and the Rosebank future development project (40%). Buzzard, Golden Eagle, and Rosebank are located in the U.K. sector of the North Sea, while Oda and the Fenja project are located in the Norwegian North Sea and the Norwegian Sea, respectively. In addition, Suncor owns, pursuant to EPSAs, working interests in the exploration and development of oilfields in the Sirte Basin in Libya, although production in Libya remained partially shut in throughout 2019 due to continued political unrest. The timing of a return to normal operations in Libya remains uncertain. Suncor also owns, pursuant to a PSC, an interest in the Ebla gas development in Syria, which has been suspended, indefinitely, since 2011 due to political unrest in the country.

REFINING AND MARKETING

Suncor's Refining and Marketing segment consists of two primary operations, the refining and supply and marketing operations discussed below, as well as the infrastructure supporting the marketing and supply of refined products, crude oil, natural gas, power and byproducts.

- **Refining and Supply** operations refine crude oil and intermediate feedstock into a wide range of petroleum and petrochemical products. Refining and Supply consists of:
    - **Eastern North America** operations include a 137,000 bbls/d refinery located in Montreal, Quebec and an 85,000 bbls/d refinery located in Sarnia, Ontario.
    - **Western North America** operations include a 142,000 bbls/d refinery located in Edmonton, Alberta and a 98,000 bbls/d refinery in 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 throughout Canada and the U.S., and the St. Clair ethanol plant in Ontario.
- **Marketing** operations sell refined petroleum products to retail, commercial and industrial customers through a combination of company-owned Petro-Canada™ and Sunoco™ locations and branded-dealers in Canada and other non-branded retail stations in the U.S., a nationwide commercial road transportation network in Canada, and a bulk sales channel in Canada.

(1) Petro-Canada™ is a registered trademark of Suncor Energy Inc. used under license.

CORPORATE AND ELIMINATIONS

The **Corporate and Eliminations** segment includes the company's investments in renewable energy projects and other activities not directly attributable to any other operating segment. Beginning in the first quarter of 2019, results from the company's Energy Trading business have been included within each of the respective reporting business segments to which the respective trading activity relates. The Energy Trading business was previously reported within the Corporate, Energy Trading and Eliminations segment.

- **Renewable Energy** includes interests in four wind farm operations in Ontario and Western Canada, being Adelaide, Chin Chute, Magrath and Sunbridge as well as the Forty Mile Wind Power project currently under construction.
- **Corporate** activities include stewardship of Suncor's debt and borrowing costs, expenses not allocated to the company's businesses, the company's captive insurance activities that insure a portion of the company's asset base and investments in clean technology.
- 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. The sale of product between the company's segments is primarily related to crude refining feedstock sold from Oil Sands to Refining and Marketing.

Three-Year History

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

2017

- **Sale of Suncor's interest in the Cedar Point wind facility.** On January 24, 2017, the company closed the sale of its 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).
- **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 common shares, beginning on May 2, 2017 and ending on May 1, 2018, through the facilities of the TSX, NYSE and/or alternative trading platforms. As at December 31, 2017, the company had repurchased 33.2 million common shares for cancellation at an average price of $42.61 per common 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 mbbls/d.
- **Sale of Suncor's interest in the Ripley wind facility.** On July 10, 2017, the company closed the sale of its 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.

- **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, bringing Suncor's ownership interest in the project at that time to 53.06%.

2018

- **First oil from Fort Hills.** On January 27, 2018, the Fort Hills project began producing paraffinic froth-treated bitumen from secondary extraction and production successfully ramped up and averaged 94% of the project's nameplate capacity of 194 mbbls/d (105 mbbls/d, net to Suncor) in the fourth quarter of 2018.

- **Renewal of NCIB and increase in share repurchases.** In May 2018, Suncor renewed its NCIB to continue to repurchase its common shares through the facilities of the TSX, NYSE and/or alternative trading platforms. On November 14, 2018, the TSX accepted a notice filed by the company of its intention to amend the NCIB effective November 19, 2018 to increase the maximum number of common shares that may be repurchased from 52,285,330 to 81,695,830 common shares between May 4, 2018 and May 3, 2019. In 2018, the company repurchased 64.4 million common shares for cancellation at an average price of $47.38 per share, for a total repurchase cost of $3.053 billion.

- **Acquisition of additional 5% interest in Syncrude.** On February 23, 2018, Suncor acquired an additional 5% interest in Syncrude from Mocal Energy Ltd. for $923 million, adding a further 17,500 bbls/d of SCO capacity and increasing the company's ownership interest to 58.74%.

- **Purchased 17.5% participating interest in the Fenja development project.** On May 31, 2018, the company acquired a 17.5% non-operated interest in the Fenja development project located offshore Norway from Faroe Petroleum Norge AS (Faroe) for acquisition costs of $70 million, plus interim settlement costs of $22 million. This project was sanctioned by its owners in December 2017, with first oil anticipated in 2021, with peak production expected to reach 34 mbbls/d (6 mbbls/d, net to Suncor) between 2021 and 2022.

- **Acquisition of additional 1.05% interest in Fort Hills.** During the first quarter of 2018, Suncor acquired an additional 1.05% interest in the Fort Hills operation for consideration of $145 million, bringing Suncor's ownership interest in the project to 54.11%. The additional interest is an outcome of the commercial settlement agreement reached among the Fort Hills partners in December 2017.

- **Disposition of Joslyn Oil Sands Mining Project (Joslyn).** On September 29, 2018, Suncor along with the other working-interest partners in Joslyn, agreed to sell 100% of their respective working interests to Canadian Natural Resources Limited (CNRL) for gross proceeds of $225 million, $82.7 million, net to Suncor. Suncor held a 36.75% working interest in Joslyn prior to the transaction.

- **Production ramp up at Hebron.** Drilling activity at Hebron was ongoing throughout 2018, with the third and fourth production wells coming online in April and October 2018, respectively. Production continued to ramp up ahead of expectations, averaging 13 mbbls/d during 2018.

- **Buzzard Phase 2 sanctioned.** During 2018, Buzzard Phase 2 was sanctioned by Suncor and the other project partners and the plan for development was approved by the U.K. Oil and Gas Authority. Suncor holds a 29.89% non-operated interest in the project. First oil is anticipated in early 2021.

- **Repayment of debt.** The company completed an early retirement of US$83 million of subsidiary debt acquired through the acquisition of Canadian Oil Sands Limited (COS) with a coupon of 7.75%, originally scheduled to mature on May 15, 2019.

- **Syncrude bi-directional pipelines.** During the fourth quarter of 2018, Suncor and its joint operating partners reached an agreement to build bi-directional interconnecting pipelines, which will connect Syncrude's Mildred Lake site and Suncor's Oil Sands Base operations. The pipelines will provide increased operational flexibility through the ability to transfer bitumen and gas oils between the two plants, enabling higher reliability and utilization. The pipelines are expected to be in-service by the second half of 2020.

- **Full implementation of autonomous haulage systems (AHS) at North Steepbank.** During 2018, the company completed the implementation of AHS at its North Steepbank mine. Autonomous haul trucks, which operate using GPS, wireless communication and perceptive

technologies, offer a number of advantages over existing truck and shovel operations, including enhanced safety performance, better operating efficiency and lower operating costs. Full implementation at Fort Hills and Millennium is expected to be completed in 2020 and 2023, respectively.

2019

- **Government of Alberta Mandatory Production Curtailment.** The Government of Alberta's mandatory production curtailment program began on January 1, 2019 and was in effect for the duration of 2019 and has been extended into 2020. Production curtailment primarily affected the company's non-upgraded bitumen production as the company maximized the production of higher value SCO barrels during the year.

- **First oil from Oda.** First oil was achieved ahead of schedule at Oda on March 16, 2019. At peak, Oda is expected to produce 35 mbbls/d (11 mbbls/d, net to Suncor).

- **Mark Little appointed President and Chief Executive Officer.** Mr. Little replaced Mr. Steve Williams who retired as Chief Executive Officer at the conclusion of the company's annual general meeting of shareholders on May 2, 2019.

- **Sanction of Terra Nova asset life extension (ALE) project.** On May 3, 2019, the company sanctioned the Terra Nova ALE project which is expected to extend the life of Terra Nova by approximately a decade and is planned for execution by the end of 2020.

- **Sale of equity interest in Canbriam.** In June 2019, Suncor completed the sale of its 37% equity interest in Canbriam for gross proceeds of $151 million. Suncor originally acquired the equity interest in Canbriam in 2018 in exchange for its northeast B.C. mineral landholdings, including associated production, along with additional cash consideration of $52 million in 2018.

- **Debt issuance and repayment.** During 2019, the company issued $750 million of 3.10% senior unsecured medium term notes and repaid US$140 million of maturing higher interest long-term debt.

- **Investment in low-carbon power cogeneration.** In the third quarter of 2019, Suncor announced that it is replacing its coke-fired boilers with a new cogeneration facility at its Oil Sands Base operations. The project is expected to provide reliable steam generation required for Suncor's extraction and upgrading operations and is expected to reduce the greenhouse gas (GHG) emissions intensity associated with steam production at Oil Sands Base operations by approximately 25%. In addition, the electricity produced will be transmitted to Alberta's power grid, providing reliable, baseload, low-carbon electricity, equivalent to approximately 8% of Alberta's current electricity demand. In total, this project will reduce the GHG emissions in the province of Alberta by approximately 2.5 Mt per year. The project is estimated to cost approximately $1.4 billion with an expected in-service date in the second half of 2023.

- **Continued investment in clean energy.** In the fourth quarter of 2019, Suncor sanctioned the Forty Mile Wind Power Project in southern Alberta. This estimated $300 million renewable power project is expected to drive value through low-carbon power generation and the retention of generated carbon credits. The company also invested $73 million in Enerkem Inc., a producer of advanced biofuels and renewable chemicals from waste.

- **Production ramp up at Hebron.** Hebron reached nameplate production of 31.6 mbbls/d, net to Suncor ahead of schedule in 2019, with six new production wells coming online throughout the year. During 2019, production at Hebron averaged 23.5 mbbls/d, net to Suncor.

- **Multi-year strategic alliance with Microsoft.** To accelerate its digital transformation, Suncor has entered into a strategic alliance with Microsoft. This alliance enables Suncor to utilize Microsoft's full range of cloud solutions to empower a connected and collaborative workforce, build an agile data platform to increase analytics capabilities and partner with experts while gaining access to leading edge technologies.

- **Completion of cross-Canada network of Petro-Canada™ electric vehicle (EV) stations** . Suncor advanced its sustainability and technology initiatives by completing its coast-to-coast Electric Highway™ network of fast-charging EV stations across Canada during the fourth quarter of 2019.

- **Continuation of NCIB.** In May 2019, Suncor renewed its NCIB to continue to repurchase its common shares through the facilities of the TSX, NYSE and/or alternative trading platforms. On December 23, 2019, the TSX accepted a notice filed by the company to increase the maximum number of common shares that may be repurchased from 50,252,231 shares, or approximately 3% of Suncor's issued and outstanding common shares as at April 30, 2019, to 78,549,178 common shares, or 5% of Suncor's issued and outstanding common shares as at April 30, 2019. In 2019, the company repurchased 55.3 million common shares for cancellation at an average price of $41.12 per common share, for a total repurchase cost of $2.274 billion. Subsequent to the end of the year, Suncor's Board of Directors approved the renewal of its share repurchase program of up to $2.0 billion beginning on March 1, 2020.

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 dewatering and treatment of mature fine tailings at Oil Sands Base, including the construction of a Permanent Aquatic Storage Structure (PASS). 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. Bitumen is currently mined from the Millennium area, which began production in 2001, and the North Steepbank area, which began production in 2011. During 2019, the company mined approximately 159 million tonnes of bitumen ore (2018 – 138 million tonnes) and processed an average of 290 mbbls/d of mined bitumen in its extraction facilities (2018 – 259 mbbls/d).

The company expects to file a regulatory application within the first quarter of 2020 to potentially replace Suncor's Millennium and North Steepbank mines as they reach the end of their useful life in approximately 2035. The application is not a project sanction and a final sanctioning decision is not expected until 2030 at the earliest.

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 kerosene hydrotreater.

In the third quarter of 2019, Suncor announced that it is replacing its coke-fired boilers with a new 800 MW cogeneration facility at Oil Sands Base. The project is expected to provide reliable steam generation required for Suncor's extraction and upgrading operations and is expected to reduce the GHG emissions intensity associated with steam production at Oil Sands Base by approximately 25%. In addition, the electricity produced will be transmitted to Alberta's power grid, providing reliable, baseload, low-carbon electricity, equivalent to approximately 8% of Alberta's current electricity demand. In total, this project will reduce the GHG emissions in the province of Alberta by approximately 2.5 Mt per year. The project is estimated to cost approximately $1.4 billion with an expected in-service date in the second half of 2023.

During 2019, Suncor averaged 313 mbbls/d of upgraded (SCO and diesel) production net of the company's internal consumption (2018 – 280 mbbls/d), mainly sourced from bitumen provided by both Oil Sands Base and In Situ operations.

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 the heated bitumen and condensed steam to drain into the lower wellbore and flow up to the surface aided by subsurface pumps or circulating gas.

- **Central Processing Facilities**

  The bitumen and water mixture is pumped to separation units at central processing facilities, where the water is removed from the bitumen, treated and recycled for use in steam generation. To facilitate shipment, In Situ operations blend diluent with the bitumen, or transport it through an insulated pipeline as hot bitumen.

- **Power and Steam Generation**

  To generate steam for operations, the company uses Once Through Steam Generators (OTSGs) or cogeneration units. OTSGs are fuelled by both purchased natural gas and produced natural gas recovered at central processing facilities. Cogeneration units are energy-efficient systems, which use natural gas combustion to power turbines that generate electricity and steam used in SAGD operations. Excess electricity generation from cogeneration units is used at Oil Sands Base facilities or sold to the Alberta power grid.

- **Maintenance and Bitumen Supply**

  Central processing facilities, steam generation units and well pads are all subject to routine inspection and maintenance cycles.

  SAGD production volumes are impacted by reservoir 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 well pairs from existing well pads or constructs new well pads to facilitate future well pair drilling and production.

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, 2019, Firebag had 17 well pads in operation, with 242 SAGD well pairs and 52 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 116 MW and, in 2019, Firebag exported approximately 285 MW of electricity to the Alberta power

grid and Oil Sands Base. There are also 13 OTSGs at the site for additional steam generation.

During 2019, Firebag production averaged 187 mbbls/d (2018 – 204 mbbls/d) with a SOR of 2.7 (2018 – 2.7). Production in 2019 was impacted by mandatory production curtailment.

Suncor has identified opportunities to debottleneck Firebag, including the completion of an emulsion handling project, an integrated well pad development and expansion of the company's Solvent SAGD program which could potentially add up to an additional 30 mbbls/d above nameplate capacity by 2024-25.

MacKay River

Production from Suncor's MacKay River operations commenced in 2002. The MacKay River central processing facilities have a bitumen processing capacity of 38 mbbls/d. As at December 31, 2019, MacKay River included seven well pads with 114 well pairs either producing or on initial steam injection. A third party owns the on-site cogeneration unit, which Suncor operates under a commercial agreement that generates steam and electricity. There are also four OTSGs at the site for additional steam generation.

During 2019, MacKay River production averaged 29 mbbls/d (2018 – 36 mbbls/d) with a SOR of 2.95 (2018 – 2.90). Production in 2019 was impacted by mandatory production curtailment. Following an outage in late 2019, MacKay River is expected to return to normal operations early in the second quarter of 2020. This follows completion of planned maintenance which has been accelerated to the first quarter of 2020 to coincide with the outage in an effort to minimize the impacts to annual production.

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, Chard and Kirby. 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 non-operated interest in Kirby (10%). In 2018, Suncor acquired a 100% working interest in leases within the Gregoire area adjacent to its Meadow Creek lands. 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, 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. The project is expected to be developed in two stages with anticipated gross production of 40 mbbls/d up to 80 mbbls/d.

In early 2020, Suncor received AER approval for the Meadow Creek West project. Meadow Creek West is expected to be developed in a single stage and has an anticipated gross production capacity of 40 mbbls/d. Timing of project sanction for Meadow Creek East and West will depend on future market conditions.

In February 2018, Suncor submitted an application for the Lewis project to the AER. Lewis is a SAGD project and is also part of Suncor's planned in situ replication strategy. Suncor holds a 100% interest in the project, located approximately 25 km northeast of Fort McMurray. The project is expected to be developed in stages, with anticipated peak production of 160 mbbls/d. Timing of project sanction for Lewis will depend on future market conditions.

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 requiring less diluent and eliminating the need for on-site upgrading facilities.

Suncor holds a 54.11% working interest in Fort Hills and is the operator of the asset. Fort Hills began producing PFT bitumen from secondary extraction in early 2018. Fort Hills has a nameplate capacity of 194 mbbls/d (gross) of bitumen (105 mbbls/d, net to Suncor). During 2019, Suncor's share of Fort Hills production averaged 85.3 mbbls/d (2018 – 67.4 mbbls/d) from approximately 51.3 million tonnes of bitumen ore mined (2018 – 38.9 million tonnes). Production in 2019 was impacted by mandatory production curtailment.

Due to a decline in forecasted heavy crude oil prices the company recorded an after-tax impairment charge of $2.803 billion on its share of Fort Hills in the fourth quarter of 2019.

Syncrude

Suncor holds a 58.74% interest in the Syncrude joint operation, which has gross bitumen conversion to SCO capacity of 350 mbbls/d (206 mbbls/d, net to Suncor). Syncrude began producing in 1978 and is operated by Syncrude Canada Ltd. (SCL). In 2006, SCL entered into a Management Services Agreement (MSA) with Imperial Oil Resources Limited (Imperial Oil) to provide business services. Imperial Oil provided notice of termination of the MSA in 2019 and the parties to the joint operation are working on a transition plan to cover the business services as provided by Imperial Oil under the MSA. The project is located near Fort McMurray and includes mining operations at Mildred Lake and Aurora North. In 2012, the Syncrude joint operating partners 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), which, subject to approvals, would consequently extend the life of Mildred Lake

by a minimum of 10 years. In 2015, a decision was made by the joint operating partners 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 is expected to 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. The Syncrude MLX-W mining area received AER approval in 2019 and remaining approvals are expected in 2020.

Suncor has been collaborating with Syncrude for several years to achieve sustained reliability improvements and reduce costs. In January 2019, Suncor and SCL entered into a master business services agreement designed to enable Suncor to provide certain business services to SCL. The proximity of Syncrude to Oil Sands Base affords an opportunity for cost management and collaboration between the company and Syncrude in order to provide opportunities to optimize assets, including during periods of planned maintenance or interruption.

In 2018, Suncor reached a formal agreement with its Syncrude joint operation partners to build bi-directional interconnecting pipelines, which will connect Syncrude's Mildred Lake site and Suncor's Oil Sands Base operations. The pipelines are expected to provide increased operational flexibility through the ability to transfer bitumen and gas oils between the two plants, enabling higher reliability and utilization. The pipelines are expected to be in-service by the second half of 2020.

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 cogeneration units which provide heat and power.

Syncrude produces a single sweet SCO product. Marketing of this product is the responsibility of the individual joint venture partners.

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 freshwater capping, a composite tails mixture of fine tails and gypsum, and centrifuge technology that separates water from tailings. The updated tailings management plans for Syncrude Aurora North and Syncrude Mildred Lake were approved by the AER in June 2018 and June 2019, respectively.

In 2019, Suncor's share of Syncrude production was limited by mandatory production curtailment, and averaged 172.3 mbbls/d (2018 – 144.2 mbbls/d). Since returning to normal operating rates in the third quarter of 2018 following a site-wide power outage in the second quarter of 2018, Syncrude has achieved reliable operations without any significant unplanned incidents. On October 29, 2019, Syncrude achieved a historic milestone, producing the three billionth (gross) barrel of crude oil at the Mildred Lake upgrading complex. Asset sustainment and maintenance capital expenditures in 2020 for Syncrude are expected to focus on a planned turnaround and reliability improvements.

Other Oil Sands Leases

Suncor indirectly owns interests in other mineable oil sands leases, including Mildred Lake West, Mildred Lake East, Lease 29, Lease 30 and Aurora South, through the company's 58.74% working interest in the Syncrude joint operation. During 2018, the company disposed of its previous 36.75% working interest in the Joslyn mining project.

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 feasibility and then to demonstrate commercial viability. The necessary validation typically occurs through a series of progressive steps which allow results to be reliably scaled and assessed for implementation.

Following a successful commercial-scale evaluation in 2018, the company began a phased implementation of AHS at its operated mine sites. Full implementation was completed at the North Steepbank mine in 2018, with full implementation at Fort Hills and Millennium is expected to be completed in 2020 and 2023, respectively. 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. During 2019, the company moved a total of 48.5 million gross tonnes of ore and overburden (2018 – 39.5 million tonnes) with AHS.

In 2018, Suncor completed the implementation of PASS technology as part of the company's accelerated dewatering project. PASS enables the dewatering of fine tailings from existing tailings ponds and the eventual reclamation and closure of tailings ponds. PASS technology consists of a proprietary mixture of coagulants and flocculants that enable water release and sequestering of fine tailings. Drainage of the first pond, Pond 8B, using the PASS technology commenced in 2018. PASS is expected to treat Suncor's legacy and new fluid tailings inventory over the life

of mine operations. During 2019, PASS increased the company's tailings treatment capacity to 230% of total annual fluid tailings produced (2018 – 165%).

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:

- Solvent+ – This is a suite of in situ solvent technologies that include various combinations of solvents and heating methods. Solvent+ is intended to provide an alternative to steam-based in situ recovery with the goal of reducing energy, GHG emissions and water usage footprints.
- In Situ Demonstration Facility (ISDF) – The ISDF is intended to enable Suncor to accelerate the commercial scale testing of in situ technologies. The goal of ISDF is to improve in situ extraction methods while materially improving environmental and economic performance. The ISDF will be located at MacKay River and received AER approval in late 2018.
- Zero-Impact Seismic – Zero-Impact Seismic is a seismic technology that has the potential to significantly reduce the surface disturbance of SAGD through the elimination of cutlines. This has the potential to reduce impacts to wildlife habitats and reduce stress on caribou populations. Suncor has completed 2D and 3D tests and will continue to advance the technology through field piloting in 2020.
- Non-Aqueous Extraction (NAE) – NAE is a potential new extraction process for oil sands mining operations that utilizes solvents as opposed to water as the primary extraction means. This has the potential to reduce water usage and tailings, and simplify mining processes, while reducing costs and GHG emissions. The company is planning a demonstration scale pilot for the 2021 to 2022 time frame.
- Partial Upgrading – Partial upgrading technology is intended to develop a low-temperature thermal cracking process to examine the potential for bitumen to be partially upgraded to a transportable and marketable product. This would increase value by decreasing the amount of diluent required, lower GHG intensity and avoid the need for a complex upgrader.

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.

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 at the company's Oil Sands Base facilities, refining diluted bitumen at Suncor's Edmonton refinery, or selling diluted bitumen to third parties. Increased bitumen sales may also be required during upgrading facility outages. In Situ bitumen production processed by Oil Sands Base upgrading facilities in 2019 increased to 116 mbbls/d or 54% (2018 – 106 mbbls/d or 44%) of total In Situ bitumen production as a result of mandatory production curtailment.

	2019		2018	
Sales Volumes and Operating Revenues – Principal Products	**mbbls/d**	**% operating revenues**	mbbls/d	% operating revenues
SCO and diesel (including Syncrude)	**483.6**	**77**	431.7	83
Bitumen	**187.5**	**22**	191.3	15
Byproducts and other operating revenues (1)	**n/a**	**1**	n/a	2
	671.1		623.0	

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

In the normal course of business, Suncor processes its proprietary sour SCO at the company's refineries or 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 and 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 processed in Suncor's Edmonton refinery, sold to other local refiners, or transferred onto the Enbridge Mainline or the TransMountain Pipeline system.

- To Cheecham, Alberta on the Enbridge Athabasca Pipeline or the Enbridge Wood Buffalo Pipeline and 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 and to Suncor's Montreal refinery from Sarnia on Enbridge's Line 9.

- To most major refining hubs via the Enbridge Mainline, Express/Platte and Keystone pipeline systems.

- To U.S. Puget Sound refineries and to global markets via the TransMountain Pipeline, as well as by rail.

Production from Syncrude is moved to market via the Pembina Athabasca Oil Sands Pipeline.

Royalties

Oil Sands 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 sanctioned 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 (net revenue royalty or NRR), subject to a minimum royalty within a range of 1% to 9% of gross revenue (gross revenue royalty or GRR). 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 royalty 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). During the post-payout phase, the annual royalty paid to the province is the greater of the GRR and NRR.

In 2019, Suncor incurred royalties at an average rate of 2% of gross revenue for Oil Sands Base (2018 – 1%) and at an average rate of 12% of gross revenue for Syncrude operations (2018 – 3%). Syncrude experienced a higher royalty rate in 2019 compared to the prior year due to a shift from GRR to NRR as a result of higher WCS prices. Oil Sands Base and the Syncrude project 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 2019, Fort Hills incurred royalties at an average rate of 2% of gross revenue (2018 – 2%).

In 2019, Suncor incurred royalties for MacKay River, which is in the post-payout phase, at an average rate of 9% of gross revenue at the NRR (2018 – 14%), and royalties at an average rate of 3% of gross revenue for Firebag (2018 – 5%), 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 throughout 2018 and 2019. As at December 31, 2019, there were 29 wells: 18 oil production wells, nine water injection wells and two gas injection wells. The Terra Nova ALE project is expected to commence in the second quarter of 2020 with the FPSO returning to service in the fourth quarter of 2020. Production at Terra Nova is planned to resume once the project is completed. The project is expected to extend the life of Terra Nova by approximately a decade.

In 2019, Suncor's share of Terra Nova production averaged 11.6 mbbls/d (2018 – 11.7 mbbls/d). Annual turnaround maintenance was completed at the Terra Nova facility in May 2019, which lasted approximately 10 days.

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/day (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, 2019, there were 72 wells: 40 oil production wells, 26 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 2019, there were eight oil production wells and nine water injection wells in the HSEU. The production wells were drilled from the GBS platform and are included in the Hibernia well count above. All nine of the water injection wells were drilled using a mobile offshore drill rig. Water for injection purposes is supplied from the GBS platform via a subsea flowline.

In 2019, Suncor's share of Hibernia production averaged 20.1 mbbls/d (2018 – 22.1 mbbls/d). Production in 2019 was impacted by an unplanned outage in the third quarter of 2019.

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, 2019, there were 45 wells: 24 oil production wells, 16 water injection wells, three gas storage wells, and two gas injection wells.

In 2007, the White Rose co-venturers signed an agreement with the Government of Newfoundland and Labrador for the development of the White Rose Extensions, which include the North Amethyst, South White Rose Extension, and West White Rose satellite fields. 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 the end of 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 began in 2018 and will continue in 2020. Due to increased capital cost estimates for the WWRP the company recorded an after-tax impairment charge of $393 million on its share of White Rose in the fourth quarter of 2019.

In 2019, Suncor's share of White Rose production averaged 4.7 mbbls/d (2018 – 6.6 mbbls/d). Turnaround maintenance was completed at White Rose in June 2019, which lasted approximately three weeks. Production at the White Rose field was shut in from mid-November 2018 to late January 2019 due to operational complications. White Rose began a staged return to normal operations, which was completed by the third quarter of 2019.

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 31.6 mbbls/d, net to Suncor, ramping up over the next several years. Hebron has a gross oil storage capacity of 1,200 mbbls and 52 well slots. First oil was achieved in November 2017.

During 2019, drilling activities continued at Hebron and will continue throughout 2020. In 2019, Suncor's share of production averaged 23.5 mbbls/d (2018 – 13.0 mbbls/d). As at December 31, 2019, there were 15 wells: 10 oil production wells, three water injection wells, one gas injection well, and one cuttings reinjection well. Annual turnaround maintenance was completed at the Hebron facility in September 2019, which lasted approximately 10 days.

Other Assets

Suncor continues to pursue opportunities offshore Newfoundland and Labrador. During 2018, Suncor was the successful bidder on two exploration licences, including operatorship of one of the two licences, west of the Terra Nova field. In addition, Suncor became an interest holder, with Equinor Canada Ltd., in a licence east of the White Rose field. These licences carry work commitments from 2019 to 2024. The company also holds interests in 48 significant discovery licences and five exploration licences offshore in this area.

E&P International – Assets and Operations

Offshore U.K. & Norway

Buzzard

The Buzzard oilfield is located in the Outer Moray Firth, 95 km northeast of Aberdeen, Scotland. Operated by CNOOC Petroleum Europe Limited (CNOOC Europe), 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. Drilling activities took place at Buzzard during 2019 with two active rigs. Four new infill wells were drilled in 2019 and Buzzard Phase 2 drilling activities took place concurrently. As at December 31, 2019, there were 48 wells: 34 oil and gas production wells and 14 water injection wells. In 2019, Suncor's share of Buzzard production averaged 31.9 mboe/d (2018 – 34.2 mboe/d). Buzzard Phase 2 was sanctioned in 2018 with production anticipated in 2021. Project execution has progressed throughout 2019 and will be tied back to the existing Buzzard complex.

Golden Eagle Area Development (GEAD)

GEAD, which is operated by CNOOC Europe, 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 facilities have gross production capacity of approximately 76 mboe/d (20 mboe/d, net to Suncor). As at December 31, 2019, there were 20 wells: 15 oil and gas production wells and five water injection wells. In 2019, Suncor's share of GEAD production averaged 9 mboe/d (2018 – 12.4 mboe/d).

Rosebank

The Rosebank future development project, in which Suncor has a 40% working interest, was discovered in December 2004 and is operated by Equinor U.K. Limited (Equinor). It 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 pre-sanction phase with a sanction decision planned for late 2022.

Oda

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. Oda was sanctioned in November 2016. The field is a subsea tie-back to the Ula platform, with peak production expected to reach 35 mbbls/d (11 mbbls/d, net to Suncor). Drilling activities were completed in 2018, and first oil was achieved in March 2019. As at December 31, 2019, there were three wells: two production wells and one water injection well.

Fenja

In 2018, Suncor acquired a 17.5% participating interest in the Fenja development project (PL586 licence). The Fenja field, which was discovered in 2014 and is operated by Neptune Energy, is located approximately 30 km southwest of the Equinor-operated Njord field in the Norwegian Sea. The project was sanctioned by the owners in late 2017, and the plan for development and operation was approved by the Ministry of Petroleum and Energy in the first half of 2018. The field will be developed with two subsea templates with six wells tied back to the Equinor-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.

Other Assets

Suncor continues to pursue other opportunities offshore of the U.K. and Norway. The company holds interests in 18 exploration licences in these areas.

Other International

Libya

In Libya, Suncor is a signatory to seven EPSAs with the National Oil Corporation (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 2019, 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, 2019, is US$359 million. Suncor declared force majeure for all exploration commitments in Libya effective December 14, 2014, and this declaration remains in effect. During 2019, the company received $264 million after-tax in risk mitigation proceeds for its Libyan assets. The proceeds may be subject to a provisional repayment which is dependent on the future performance and cash flows from Suncor's Libyan assets.

Suncor's share of production in Libya on an economic basis averaged 2.3 mbbls/d in 2019 (2018 – 2.9 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 and Offshore U.K. & Norway 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:

	2019		2018	
Sales Volumes	**mboe/d**	**% operating revenues**	mboe/d	% operating revenues
E&P Canada				
Crude oil and NGLs	**60.8**	**57**	52.8	52
Natural gas	**—**	**—**	0.5	—
E&P International				
Crude oil and NGLs[(1)]	**44.3**	**42**	48.7	47
Natural gas	**0.8**	**1**	0.8	1
Total Exploration and Production				
Crude oil and NGLs	**105.1**	**99**	101.5	99
Natural gas	**0.8**	**1**	1.3	1

(1) E&P International Crude oil and NGLs includes production volumes for Libya on an economic 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.
- 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.

- Oda – crude oil and natural gas is transported via the third-party operated Norpipe to the Teesside terminal in the United Kingdom, where it is shipped to market as part of the Ekofisk Blend crude stream. Natural gas from Oda is injected into the Ula reservoir to improve oil recovery from the Ula field.

Royalties

East Coast Canada

Suncor's East Coast projects are subject to Royalty Agreements and Regulations issued by the Government of Newfoundland and Labrador. To date, the royalty regime for each project has been negotiated on an individual basis. On November 1, 2017, the Province of Newfoundland and Labrador promulgated the Generic Royalty Regime (GORR) for future projects. The current East Coast royalty regime has a tiered rate structure ranging from a minimum of 1% of gross revenue to a maximum of 42.5% of net revenue (gross revenue less eligible operating and capital costs). The tiered structure is based upon various profitability levels. An East Coast project will be 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).

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. Tier two is an additional 12.5% of net revenue. During 2019, Terra Nova royalties averaged 17% of gross revenue (2018 – 20%).

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 which occurred in 2019.

Hibernia royalties (including the HSEU) and NPI combined to average 32% of gross revenue for 2019 (2018 – 23%).

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 tier 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 2019, total White Rose royalties averaged 4% of gross revenue (2018 – 7%).

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 2019, Hebron royalties averaged 1% of gross revenue (2018 – 1%).

E&P International

There are no royalties on oil and gas production from Offshore U.K. & Norway; however, oil and gas profits offshore U.K. are subject to a 40% income tax rate. In addition, oil and gas profits offshore 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, with a flexible configuration that allows processing of sweet SCO from the company's Oil Sands operations, WCS, conventional 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 123.8 mbbls/d in 2019 (2018 – 124.1 mbbls/d).

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 355,000 metric tonnes in 2019 (2018 – 372,000 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 2019, the plant produced 400 million litres of ethanol (2018 – 402 million litres).

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 the other Syncrude joint venture partners' 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 heavy 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 crude 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 the capacity to process 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 and Wyoming. 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, 2019 and 2018.

Average Daily Crude Throughput	Montreal		Sarnia		Edmonton		Commerce City	
(mbbls/d, except as noted)	**2019**	2018	**2019**	2018	**2019**	2018	**2019**	2018
Sweet synthetic	**7.9**	8.9	**24.8**	29.7	**54.9**	50.1	**—**	—
Sour synthetic	**—**	—	**31.8**	25.7	**45.3**	32.8	**9.4**	9.2
Diluted bitumen	**20.6**	22.1	**—**	—	**43.0**	35.6	**9.9**	11.2
Sweet conventional	**89.0**	90.0	**0.3**	3.1	**—**	—	**63.9**	65.7
Sour conventional	**8.0**	9.2	**21.0**	19.4	**—**	4.7	**9.4**	13.4
Total	**125.5**	130.2	**77.9**	77.9	**143.2**	123.2	**92.6**	99.5
Utilization (%)	**92**	95	**92**	92	**101**	87	**94**	102
Equity Crude Processed[(1)]	**7.7**	7.0	**51.6**	45.0	**121.3**	99.3	**9.4**	9.2

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

Refined Petroleum Production Yield Mix	Montreal		Sarnia		Edmonton		Commerce City	
(%)	**2019**	2018	**2019**	2018	**2019**	2018	**2019**	2018
Gasoline	**38**	41	**47**	51	**43**	44	**49**	48
Distillates	**38**	37	**39**	37	**52**	50	**34**	35
Other	**24**	22	**14**	12	**5**	6	**17**	17

Distribution Terminals and Pipelines

Suncor owns and operates 13 major refined product terminals across Canada (including terminals adjacent to refineries) and three 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.

As at December 31, 2019, Suncor's ownership interests in certain pipelines were as follows:

Pipeline	Ownership	Type	Origin	Destinations
Portland-Montreal Pipeline	23.80%	Crude oil	Portland, Maine	Montreal, Quebec
Trans-Northern Pipeline	33.30%	Refined product	Montreal, Quebec	Ontario – Ottawa, Toronto & Oakville
Sun-Canadian Pipeline	55.00%	Refined product	Sarnia, Ontario	Ontario – Toronto, London & Hamilton
Alberta Products Pipeline	35.00%	Refined product	Edmonton, Alberta	Calgary, Alberta
Rocky Mountain Crude Pipeline	100.00%	Crude oil	Guernsey, Wyoming	Denver, Colorado
Centennial Pipeline	100.00%	Crude oil	Guernsey, Wyoming	Cheyenne, Wyoming
Oil Sands Pipeline	100.00%	Crude oil	Fort McMurray, Alberta	Edmonton, Alberta

Marketing – Assets and Operations

Suncor's retail service station network operates nationally in Canada primarily under the Petro-Canada™ brand. As at December 31, 2019, this network consisted of 1,547 outlets across Canada, of which 796 locations are company-owned locations and 751 are branded-dealers. Selected locations along the Trans-Canada highway comprise the coast-to-coast Electric Highway™ network of fast charging EV stations. In addition, refined products are marketed through independent dealers and joint operations. Suncor's Canadian retail network had sales of gasoline motor fuels averaging approximately 4.9 million litres per site in 2019 (2018 – 4.8 million litres).

Suncor's Colorado retail network consists of 44 owned or leased Shell™, Exxon™ or Mobil™ branded outlets. Suncor also has product supply agreements with 142 Shell™-branded sites in both Colorado and Wyoming, and with 53 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 and Wholesale Summary

	As at December 31	
Locations	**2019**	2018
Retail Service Stations – Canada		
Petro-Canada™ -branded	**1 546**	1 527
Sunoco™ -branded	**1**	1
	1 547	1 528
Retail Service Stations[(1)] – U.S.		
Shell™ -branded retail service stations – Colorado/Wyoming	**177**	180
Exxon™ -branded retail service stations – Colorado	**42**	40
Mobil™ -branded retail service stations – Colorado	**20**	18
	239	238
Wholesale Cardlock Sites – Canada		
Petro-Canada™-branded cardlock sites (PETRO-PASS™)	**310**	307

(1) Shell™ is a registered U.S. trademark of SHELL TRADEMARK MANAGEMENT B.V., and Exxon™ and Mobil™ are registered U.S. trademarks of Exxon Mobil Corporation.

Refined Products Sales Volumes

	2019		2018	
Sales Volumes	**mbbls/d**	**% operating revenues**	mbbls/d	% operating revenues
Gasoline (includes motor and aviation gasoline)				
Eastern North America	**119.8**		117.8	
Western North America	**126.8**		127.8	
	246.6	**46**	245.6	47
Distillates (includes diesel and heating oils, and aviation jet fuels)				
Eastern North America	**102.9**		95.8	
Western North America	**115.2**		107.6	
	218.1	**40**	203.4	39
Other (includes heavy fuel oil, asphalts, petrochemicals, other)				
Eastern North America	**48.8**		52.7	
Western North America	**25.9**		25.6	
	74.7	**14**	78.3	15
	539.4		527.3	

Sales volumes for specific products are moderately affected by seasonal cycles: gasoline sales are typically higher during the summer driving season; heating oil sales are typically higher during the winter season; diesel sales are typically higher during the drilling season at the beginning of the year in Western Canada and during agricultural planting and harvest seasons in early spring and late summer, respectively; and 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, transportation fuels, specialty products and feedstock, natural gas, and electricity – and has trading offices in Canada, the U.K. and the U.S. Energy Trading manages open price exposure along the Suncor value chain and provides commodity supply, transportation and storage while optimizing price realizations for Suncor's products. The company's customers include mid- to large-sized commercial and industrial consumers, utility companies and energy producers. Beginning in the first quarter of 2019, results from the company's Energy Trading business have been included within each of the respective reporting business segments to which the respective trading activity relates. The Energy Trading business was previously reported within the Corporate, Energy Trading and Eliminations segment.

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 contractual arrangements for other midstream infrastructure, such as pipeline, storage capacity and rail access, to optimize delivery of existing and future growth production, while generating earnings on select trading 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 company's four refineries, managing crude inventory levels during refinery turnarounds and periods of unplanned maintenance, as well as managing external impacts from pipeline disruptions. Energy Trading also moves Suncor's refinery production to market and ensures supply to Suncor's branded retail and wholesale marketing channels. 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 has secured a number of sites for potential future wind and solar power projects that are in various stages of development, including the Forty Mile Wind Power Project in southeast Alberta. Suncor sanctioned the Forty Mile Wind Power Project in late 2019; this 200 MW renewable power project has an estimated total capital spend of $300 million with completion expected in late 2021.

Suncor's wind power projects as at December 31, 2019:

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 at December 31	2019	2018
Oil Sands[1][2]	**6 400**	6 297
Exploration and Production[2]	**351**	340
Refining and Marketing[2]	**2 824**	2 939
Corporate and Eliminations[2][3]	**3 314**	2 904
Total	**12 889**	12 480

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

(2) Prior period information has been re-classed to conform to current period presentation.

(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 31% or 4,322 of the company's employees were covered by collective agreements at the end of 2019. The company completed negotiations in 2019 and collective agreements are now in place with United Steelworkers at the Commerce City refinery and with Unifor at Oil Sands Base and Firebag, as well as the Edmonton refinery, the Montreal refinery and the Burrard, Edmonton, London, Montreal and Oakville terminals. Negotiations are in progress for the Terra Nova and Ottawa Terminal collective agreements, representing approximately 71 employees.

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 and Suncor's values. 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 they understand the requirements of the Code, and provide confirmation of compliance with the Code since their 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 that 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. It also reinforces Suncor's commitment to sustainable development and encourages Suncor's business associates to work with the company to seek ways to reduce environmental impacts, support the communities in which Suncor works and collectively achieve economic growth. 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 is intended to ensure 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, including: the belief that a process for human rights impact assessment undertaken regularly is essential to identify, prevent, mitigate and remedy potential impacts on human rights; a commitment to providing a working environment that is free from harassment, violence, intimidation and

other disruptive behaviours; a commitment to respecting the cultures, customs and values of the communities in which the company operates; the belief that security policies should be consistent with international human rights standards; and the belief that employees and stakeholders affected by the company's activities should have access to grievance mechanisms that are legitimate, accessible, predictable, equitable and transparent. The policy makes clear that the scope of Suncor's human rights due diligence should include 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 Suncor's belief that successful stakeholder relations provide significant mutual benefits, including enabling informed decision-making, resolving issues with timely, cost-effective and mutually beneficial solutions, building stronger communities and supporting shared learning.

Suncor has a Canadian Indigenous Relations Policy, which affirms Suncor's desire to work in collaboration with Indigenous Peoples to create shared value. The policy sets the foundation for a consistent approach to the company's relationships with Indigenous 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 Indigenous 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 Indigenous 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 (EHS&SD) Committee of the Board of Directors meets quarterly to review Suncor's effectiveness in meeting its EHS&SD obligations. The committee also reviews the company's strategies and policies, with respect to EHS&SD, given legal, industry and community standards. The EHS&SD Committee also monitors management's performance and emerging trends and issues in these areas. In addition, the EHS&SD Committee has oversight over Suncor's performance with respect to the company's social goal regarding building mutual trust and respect with the Indigenous Peoples of Canada, and reviews Suncor's annual Report on Sustainability reporting on Suncor's EHS&SD progress, plans and performance objectives, as well as disclosure on lobbying.

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 EH&S performance. The awards program highlights progress on safety and environmental 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. The Canadian Indigenous Relations Policy is available in Cree and Dene audio translations.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Date of Statement

The Statement of Reserves Data and Other Oil and Gas Information outlined below is dated February 26, 2020, with an effective date of December 31, 2019. 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 January 27, 2020.

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 dated February 21, 2020 (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 (collectively, E&P Canada), and conventional assets offshore of the U.K. and Norway (collectively, Offshore U.K. & Norway), is based upon evaluations conducted by Sproule Associates Limited or Sproule International Limited (collectively, Sproule), contained in their reports dated February 21, 2020 (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, hydrogeology, 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 to the evaluation of reserves, 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, yield rates for upgraded production of SCO from bitumen, and future abandonment and reclamation costs – 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, among 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, 2019. 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 of this AIF.

- Government Action

  Government intervention, including mandatory production curtailments, could create long-term market uncertainty, which could have a material adverse effect on Suncor's reserves. Refer to the Risk Factors – Government/Regulatory and Policy Effectiveness section of this AIF.

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, 2019
(forecast prices and costs)[2]

	SCO[3] (mmbbls)		Bitumen (mmbbls)		Light Crude & Medium Crude Oil[4] (mmbbls)		Conventional Natural Gas[6] (bcfe)		Total (mmboe)	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Proved Developed Producing										
Mining	1 966	1 800	896	833	—	—	—	—	2 862	2 632
In Situ	231	201	99	85	—	—	—	—	330	286
E&P Canada	—	—	—	—	72	63	—	—	72	63
Total Canada	2 197	2 001	996	917	72	63	—	—	3 265	2 981
Offshore U.K. & Norway	—	—	—	—	47	47	2	2	48	48
Total Proved Developed Producing	**2 197**	**2 001**	**996**	**917**	**120**	**110**	**2**	**2**	**3 313**	**3 029**
Proved Developed Non-Producing										
Mining	—	—	—	—	—	—	—	—	—	—
In Situ	—	—	—	—	—	—	—	—	—	—
E&P Canada	—	—	—	—	—	—	—	—	—	—
Total Canada	—	—	—	—	—	—	—	—	—	—
Offshore U.K. & Norway	—	—	—	—	—	—	—	—	—	—
Total Proved Developed Non-Producing	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Proved Undeveloped										
Mining	—	—	—	—	—	—	—	—	—	—
In Situ	627	520	679	558	—	—	—	—	1 306	1 079
E&P Canada	—	—	—	—	44	41	—	—	44	41
Total Canada	627	520	679	558	44	41	—	—	1 350	1 120
Offshore U.K. & Norway	—	—	—	—	8	8	13	13	10	10
Total Proved Undeveloped	**627**	**520**	**679**	**558**	**51**	**49**	**13**	**13**	**1 359**	**1 130**
Proved										
Mining	1 966	1 800	896	833	—	—	—	—	2 862	2 632
In Situ	858	721	779	643	—	—	—	—	1 636	1 365
E&P Canada	—	—	—	—	116	104	—	—	116	104
Total Canada	2 824	2 521	1 675	1 476	116	104	—	—	4 615	4 101
Offshore U.K. & Norway	—	—	—	—	56	56	15	15	58	58
Total Proved	**2 824**	**2 521**	**1 675**	**1 476**	**172**	**160**	**15**	**15**	**4 673**	**4 159**
Probable										
Mining	601	547	469	402	—	—	—	—	1 070	950
In Situ	1 143	902	325	242	—	—	—	—	1 468	1 144
E&P Canada	—	—	—	—	162	131	—	—	162	131
Total Canada	1 744	1 450	794	644	162	131	—	—	2 700	2 224
Offshore U.K. & Norway	—	—	—	—	32	32	16	16	35	35
Total Probable	**1 744**	**1 450**	**794**	**644**	**194**	**163**	**16**	**16**	**2 735**	**2 259**
Proved Plus Probable										
Mining	2 567	2 347	1 365	1 235	—	—	—	—	3 932	3 582
In Situ	2 001	1 624	1 103	885	—	—	—	—	3 104	2 509
E&P Canada	—	—	—	—	278	235	—	—	278	235
Total Canada	4 568	3 971	2 469	2 120	278	235	—	—	7 314	6 325
Offshore U.K. & Norway	—	—	—	—	88	88	31	31	93	93
Total Proved Plus Probable	**4 568**	**3 971**	**2 469**	**2 120**	**366**	**323**	**31**	**31**	**7 407**	**6 419**

Please see Notes (1) through (4) and (6) 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, 2019
(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	Proved Plus Probable
	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	bcfe	bcfe	bcfe	mmboe	mmboe	mmboe
Mining															
December 31, 2018	2 069	621	2 690	942	496	1 438	—	—	—	—	—	—	3 011	1 117	4 128
Extensions & Improved Recovery[7]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Technical Revisions[8]	41	(20)	21	(15)	(27)	(42)	—	—	—	—	—	—	26	(47)	(21)
Discoveries[9]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Acquisitions[10]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions[11]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors[12]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Production[13]	(144)	—	(144)	(31)	—	(31)	—	—	—	—	—	—	(174)	—	(174)
December 31, 2019	**1 966**	**601**	**2 567**	**896**	**469**	**1 365**	**—**	**—**	**—**	**—**	**—**	**—**	**2 862**	**1 070**	**3 932**
In Situ															
December 31, 2018	729	1 175	1 904	770	387	1 157	—	—	—	—	—	—	1 499	1 562	3 061
Extensions & Improved Recovery[7]	122	(36)	86	71	(42)	29	—	—	—	—	—	—	193	(78)	115
Technical Revisions[8]	37	4	41	(22)	(20)	(41)	—	—	—	—	—	—	15	(16)	—
Discoveries[9]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Acquisitions[10]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions[11]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors[12]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Production[13]	(30)	—	(30)	(41)	—	(41)	—	—	—	—	—	—	(71)	—	(71)
December 31, 2019	**858**	**1 143**	**2 001**	**779**	**325**	**1 103**	**—**	**—**	**—**	**—**	**—**	**—**	**1 636**	**1 468**	**3 104**
E&P Canada															
December 31, 2018	—	—	—	—	—	—	123	174	297	—	—	—	123	174	297
Extensions & Improved Recovery[7]	—	—	—	—	—	—	4	7	11	—	—	—	4	7	11
Technical Revisions[8]	—	—	—	—	—	—	12	(19)	(8)	—	—	—	12	(19)	(8)
Discoveries[9]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Acquisitions[10]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

Dispositions[11]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors[12]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Production[13]	—	—	—	—	—	—	(22)	—	(22)	—	—	—	(22)	—	(22)
December 31, 2019	**—**	**—**	**—**	**—**	**—**	**—**	**116**	**162**	**278**	**—**	**—**	**—**	**116**	**162**	**278**
Total Canada															
December 31, 2018	2 798	1 796	4 593	1 712	883	2 595	123	174	297	—	—	—	4 632	2 853	7 485
Extensions & Improved Recovery[7]	122	(36)	86	71	(42)	29	4	7	11	—	—	—	196	(71)	125
Technical Revisions[8]	78	(16)	62	(36)	(47)	(83)	12	(19)	(8)	—	—	—	53	(82)	(28)
Discoveries[9]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Acquisitions[10]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions[11]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors[12]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Production[13]	(173)	—	(173)	(72)	—	(72)	(22)	—	(22)	—	—	—	(268)	—	(268)
December 31, 2019	**2 824**	**1 744**	**4 568**	**1 675**	**794**	**2 469**	**116**	**162**	**278**	**—**	**—**	**—**	**4 615**	**2 700**	**7 314**

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, 2019
(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	Proved Plus Probable
	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	bcfe	bcfe	bcfe	mmboe	mmboe	mmboe
Offshore U.K. & Norway															
December 31, 2018	—	—	—	—	—	—	52	37	88	14	17	32	54	40	94
Extensions & Improved Recovery[7]	—	—	—	—	—	—	1	1	2	—	—	1	1	1	3
Technical Revisions[8]	—	—	—	—	—	—	19	(6)	13	2	(2)	1	19	(6)	13
Discoveries[9]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Acquisitions[10]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions[11]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors[12]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Production[13]	—	—	—	—	—	—	(16)	—	(16)	(2)	—	(2)	(16)	—	(16)
December 31, 2019	**—**	**—**	**—**	**—**	**—**	**—**	**56**	**32**	**88**	**15**	**16**	**31**	**58**	**35**	**93**
Other International [14]															
December 31, 2018	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Extensions & Improved Recovery[7]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Technical Revisions[8]	—	—	—	—	—	—	6	—	6	—	—	—	6	—	6
Discoveries[9]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Acquisitions[10]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions[11]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors[12]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Production[13][14]	—	—	—	—	—	—	(6)	—	(6)	—	—	—	(6)	—	(6)
December 31, 2019	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Total															
December 31, 2018	2 798	1 796	4 593	1 712	883	2 595	174	211	385	14	17	32	4 686	2 892	7 579
Extensions & Improved Recovery[7]	122	(36)	86	71	(42)	29	5	8	13	—	—	1	198	(70)	128
Technical Revisions[8]	78	(16)	62	(36)	(47)	(83)	36	(25)	11	2	(2)	1	78	(88)	(10)
Discoveries[9]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

Acquisitions[10]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions[11]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors[12]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Production[13]	(173)	—	(173)	(72)	—	(72)	(44)	—	(44)	(2)	—	(2)	(289)	—	(289)
December 31, 2019	**2 824**	**1 744**	**4 568**	**1 675**	**794**	**2 469**	**172**	**194**	**366**	**15**	**16**	**31**	**4 673**	**2 735**	**7 407**

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, 2019

(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 & Medium Crude Oil for E&P Canada include immaterial quantities of Heavy Crude Oil as follows: Proved Developed Producing of 26 mmbbls, Proved Undeveloped of 28 mmbbls, Proved of 54 mmbbls, Probable of 37 mmbbls and Proved Plus Probable of 91 mmbbls. Net volumes of Light Crude & Medium Crude Oil for E&P Canada include immaterial quantities of Heavy Crude Oil as follows: Proved Developed Producing of 25 mmbbls, Proved Undeveloped of 27 mmbbls, Proved of 52 mmbbls, Probable of 30 mmbbls and Proved Plus Probable of 82 mmbbls.

(5) Light Crude & Medium Crude Oil Technical Revisions for E&P Canada include quantities of Heavy Crude Oil as follows: Proved of 1.5 mmbbls, Probable of (2.5) mmbbls and Proved Plus Probable of (0.9) mmbbls.

(6) Conventional Natural Gas includes immaterial amounts of NGLs (0.6 mmbbls of Proved and 1.3 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 2019 are primarily a result of drilling extensions at Firebag.

(8) Technical Revisions include changes in previous estimates resulting from new technical data or revised interpretations. Changes in 2019 are primarily due to new information obtained during the year, including drilling results and ongoing field performance. 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 and are as a result of the confirmation of the existence of an accumulation of a significant quantity of potentially recoverable petroleum. There were no discoveries in 2019.

(10) Acquisitions are additions to reserves estimates as a result of purchasing interests in oil and gas properties.

(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.

For any given pool, 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

Net Present Values of Future Net Revenues Before Income Taxes [1]
as at December 31, 2019
(forecast prices and costs)

	(in $ millions, discounted at % per year)					Unit Value [2]
	0%	5%	10%	15%	20%	($/boe)
Proved Developed Producing						
Mining	37 000	28 445	19 865	14 479	11 104	7.55
In Situ	8 986	7 891	6 997	6 275	5 691	24.49
E&P Canada	1 833	2 047	2 066	2 006	1 919	32.88
Total Canada	47 820	38 383	28 927	22 760	18 714	9.70
Offshore U.K. & Norway	2 142	2 103	2 022	1 927	1 834	42.31
Total Proved Developed Producing	**49 961**	**40 486**	**30 949**	**24 688**	**20 547**	**10.22**
Proved Developed Non-Producing						
Mining	—	—	—	—	—	—
In Situ	—	—	—	—	—	—
E&P Canada	—	—	—	—	—	—
Total Canada	—	—	—	—	—	—
Offshore U.K. & Norway	38	35	34	32	31	74.23
Total Proved Developed Non-Producing	**38**	**35**	**34**	**32**	**31**	**74.23**
Proved Undeveloped						
Mining	—	—	—	—	—	—
In Situ	36 739	19 520	11 333	7 085	4 696	10.50
E&P Canada	1 972	1 723	1 484	1 283	1 121	35.97
Total Canada	38 711	21 243	12 817	8 368	5 817	11.44
Offshore U.K. & Norway	437	359	294	240	196	29.93
Total Proved Undeveloped	**39 147**	**21 601**	**13 111**	**8 609**	**6 013**	**11.60**
Proved						
Mining	37 000	28 445	19 865	14 479	11 104	7.55
In Situ	45 725	27 411	18 329	13 360	10 387	13.43
E&P Canada	3 805	3 770	3 550	3 290	3 039	34.11
Total Canada	86 530	59 626	41 744	31 129	24 530	10.18
Offshore U.K. & Norway	2 616	2 497	2 349	2 200	2 061	40.46
Total Proved	**89 146**	**62 123**	**44 093**	**33 329**	**26 591**	**10.60**
Probable						
Mining	27 472	11 922	6 432	4 010	2 758	6.77
In Situ	71 102	19 872	7 521	3 792	2 378	6.57
E&P Canada	7 163	5 076	3 584	2 589	1 915	27.40
Total Canada	105 737	36 869	17 536	10 391	7 052	7.88
Offshore U.K. & Norway	2 079	1 690	1 366	1 117	929	38.99
Total Probable	**107 816**	**38 559**	**18 903**	**11 508**	**7 980**	**8.37**
Proved Plus Probable						
Mining	64 472	40 367	26 297	18 489	13 862	7.34
In Situ	116 827	47 283	25 850	17 152	12 765	10.30
E&P Canada	10 968	8 846	7 134	5 879	4 955	30.37
Total Canada	192 267	96 495	59 281	41 520	31 582	9.37

Offshore U.K. & Norway	4 696	4 187	3 715	3 317	2 989	39.91
Total Proved Plus Probable	**196 963**	**100 682**	**62 996**	**44 837**	**34 571**	**9.81**

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, 2019
(forecast prices and costs)

	(in $ millions, discounted at % per year)				
	0%	5%	10%	15%	20%
Proved Developed Producing					
Mining	28 142	23 022	16 293	11 982	9 272
In Situ	7 042	6 204	5 505	4 937	4 475
E&P Canada	1 473	1 715	1 758	1 718	1 647
Total Canada	36 657	30 941	23 555	18 637	15 394
Offshore U.K. & Norway	1 246	1 228	1 186	1 137	1 088
Total Proved Developed Producing	**37 902**	**32 169**	**24 741**	**19 774**	**16 482**
Proved Developed Non-Producing					
Mining	—	—	—	—	—
In Situ	—	—	—	—	—
E&P Canada	—	—	—	—	—
Total Canada	—	—	—	—	—
Offshore U.K. & Norway	23	22	21	20	19
Total Proved Developed Non-Producing	**23**	**22**	**21**	**20**	**19**
Proved Undeveloped					
Mining	—	—	—	—	—
In Situ	28 032	14 747	8 466	5 228	3 418
E&P Canada	1 459	1 281	1 097	941	814
Total Canada	29 490	16 027	9 563	6 169	4 232
Offshore U.K. & Norway	395	325	266	219	179
Total Proved Undeveloped	**29 885**	**16 352**	**9 829**	**6 387**	**4 411**
Proved					
Mining	28 142	23 022	16 293	11 982	9 272
In Situ	35 074	20 950	13 971	10 165	7 893
E&P Canada	2 932	2 996	2 855	2 659	2 461
Total Canada	66 147	46 968	33 118	24 806	19 626
Offshore U.K. & Norway	1 663	1 574	1 473	1 376	1 286
Total Proved	**67 810**	**48 542**	**34 591**	**26 181**	**20 912**
Probable					
Mining	21 595	9 138	4 813	2 937	1 981
In Situ	54 598	15 186	5 756	2 919	1 841
E&P Canada	5 283	3 739	2 593	1 828	1 315
Total Canada	81 476	28 063	13 162	7 685	5 137
Offshore U.K. & Norway	1 051	892	746	628	535
Total Probable	**82 527**	**28 954**	**13 907**	**8 312**	**5 672**
Proved Plus Probable					
Mining	49 737	32 159	21 106	14 920	11 253
In Situ	89 672	36 136	19 727	13 084	9 734
E&P Canada	8 214	6 735	5 448	4 487	3 776
Total Canada	147 623	75 030	46 280	32 490	24 763
Offshore U.K. & Norway	2 714	2 466	2 219	2 003	1 821

Total Proved Plus Probable	**150 337**	**77 496**	**48 499**	**34 494**	**26 584**

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

Total Future Net Revenues[1]
as at December 31, 2019
(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	245 328	20 587	139 235	30 021	18 485	37 000	8 859	28 142
In Situ	24 586	3 111	9 653	2 277	559	8 986	1 944	7 042
E&P Canada	6 475	826	1 890	372	1 554	1 833	360	1 473
Total Canada	276 390	24 524	150 779	32 670	20 597	47 820	11 163	36 657
Offshore U.K. & Norway	4 282	—	1 383	91	665	2 142	896	1 246
Total Proved Developed Producing	**280 671**	**24 524**	**152 162**	**32 762**	**21 262**	**49 961**	**12 059**	**37 902**
Proved Developed Non-Producing								
Mining	—	—	—	—	—	—	—	—
In Situ	—	—	—	—	—	—	—	—
E&P Canada	—	—	—	—	—	—	—	—
Total Canada	—	—	—	—	—	—	—	—
Offshore U.K. & Norway	38	—	1	—	—	38	15	23
Total Proved Developed Non-Producing	**38**	**—**	**1**	**—**	**—**	**38**	**15**	**23**
Proved Undeveloped								
Mining	—	—	—	—	—	—	—	—
In Situ	107 454	18 257	33 569	17 687	1 202	36 739	8 707	28 032
E&P Canada	4 090	227	1 058	503	331	1 972	513	1 459
Total Canada	111 544	18 484	34 626	18 190	1 533	38 711	9 220	29 490
Offshore U.K. & Norway	835	—	98	234	66	437	42	395
Total Proved Undeveloped	**112 379**	**18 484**	**34 724**	**18 424**	**1 599**	**39 147**	**9 262**	**29 885**
Proved								
Mining	245 328	20 587	139 235	30 021	18 485	37 000	8 859	28 142
In Situ	132 040	21 368	43 222	19 964	1 761	45 725	10 652	35 074
E&P Canada	10 565	1 053	2 948	875	1 884	3 805	873	2 932
Total Canada	387 934	43 008	185 405	50 860	22 131	86 530	20 383	66 147
Offshore U.K. & Norway	5 155	—	1 482	326	731	2 616	953	1 663
Total Proved	**393 089**	**43 008**	**186 887**	**51 186**	**22 862**	**89 146**	**21 336**	**67 810**
Probable								
Mining	111 437	12 889	59 234	9 849	1 993	27 472	5 877	21 595
In Situ	188 644	38 759	52 355	25 077	1 352	71 102	16 503	54 598
E&P Canada	16 622	3 106	3 743	1 981	629	7 163	1 881	5 283
Total Canada	316 703	54 754	115 332	36 907	3 974	105 737	24 261	81 476
Offshore U.K. & Norway	3 366	—	1 034	144	108	2 079	1 029	1 051
Total Probable	**320 069**	**54 754**	**116 366**	**37 051**	**4 082**	**107 816**	**25 289**	**82 527**
Proved Plus Probable								
Mining	356 766	33 476	198 470	39 870	20 478	64 472	14 735	49 737
In Situ	320 685	60 127	95 577	45 041	3 113	116 827	27 155	89 672
E&P Canada	27 187	4 159	6 691	2 856	2 513	10 968	2 754	8 214

Total Canada	704 637	97 762	300 737	87 767	26 104	192 267	44 644	147 623
Offshore U.K. & Norway	8 521	—	2 516	470	839	4 696	1 981	2 714
Total Proved Plus Probable	**713 158**	**97 762**	**303 253**	**88 237**	**26 944**	**196 963**	**46 625**	**150 337**

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

Future Net Revenues by Product Type[1]
as at December 31, 2019
(forecast prices and costs)

(before income taxes, discounted at 10% per year)	$ millions	Unit Value $/boe[2]
Proved Developed Producing		
SCO	21 529	10.76
Bitumen	5 333	5.81
Light Crude & Medium Crude Oil	2 594	30.52
Heavy Crude Oil	1 483	58.65
Conventional Natural Gas[3]	10	31.12
Total Proved Developed Producing	**30 949**	**10.22**
Proved		
SCO	28 129	11.16
Bitumen	10 065	6.82
Light Crude & Medium Crude Oil	3 331	31.01
Heavy Crude Oil	2 521	48.21
Conventional Natural Gas[3]	47	19.50
Total Proved	**44 093**	**10.60**
Proved Plus Probable		
SCO	40 642	10.23
Bitumen	11 506	5.43
Light Crude & Medium Crude Oil	7 296	30.28
Heavy Crude Oil	3 465	42.29
Conventional Natural Gas[3]	89	17.40
Total Proved Plus Probable	**62 997**	**9.81**

(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) Conventional natural gas includes associated 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 57% of Firebag bitumen production is estimated to be upgraded to SCO from 2020 to 2035 and 100% thereafter. These assumptions have resulted in a $3.4 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

The forecast price and cost assumptions include changes in wellhead selling prices, take into account escalation with respect to future operating and capital costs, and assume the continuance of current laws and regulations. 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., all of whom are independent qualified reserves evaluators, dated January 1, 2020. Resultant forecasts are set out below. To the extent there are fixed or presently determinable future prices 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 have been incorporated into the forecast prices as applied to the pertinent properties. Benchmark forecast prices have been adjusted for quality differentials and transportation costs applicable to the specific evaluation areas and products. The inflation rates utilized in cost forecasts were nil in 2020, 1.7% in 2021, and 2.0% thereafter.

Prices Impacting Reserves Tables

Forecast	Brent North Sea[1]	WTI Cushing Oklahoma[2]	WCS Hardisty Alberta[3]	Light Sweet Edmonton Alberta[4]	Pentanes Plus Edmonton Alberta[5]	AECO Gas[6]	National Balancing Point North Sea[7]
Year	US$/bbl	US$/bbl	Cdn$/bbl	Cdn$/bbl	Cdn$/bbl	Cdn$/mmbtu	Cdn$/mmbtu
2019[8]	64.18	57.03	58.75	69.21	70.14	1.75	3.98
2020	66.33	61.00	57.57	72.64	76.83	2.04	7.48
2021	67.94	63.75	62.35	76.06	79.82	2.32	7.90
2022	70.06	66.18	64.33	78.35	82.30	2.62	8.23
2023	71.66	67.91	66.23	80.71	84.72	2.71	8.70
2024	73.27	69.48	67.96	82.64	86.71	2.81	8.97
2025	74.57	71.07	69.72	84.60	88.73	2.89	9.24
2026	76.22	72.68	71.49	86.57	90.77	2.96	9.47
2027	77.83	74.24	73.19	88.49	92.76	3.03	9.61
2028	79.36	75.73	74.80	90.31	94.65	3.10	9.76
2029	80.92	77.24	76.43	92.17	96.57	3.17	9.90
2030	82.54	78.79	77.96	94.01	98.53	3.24	10.10
2031	84.19	80.36	79.52	95.89	100.50	3.30	10.30
2032	85.87	81.97	81.11	97.81	102.51	3.37	10.51
2033	87.59	83.61	82.73	99.76	104.56	3.43	10.72
2034	89.35	85.28	84.39	101.76	106.65	3.50	10.93
2035+	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr

(1) Price used when determining offshore light crude oil and medium crude oil and heavy crude oil reserves for E&P Canada and Offshore U.K. & Norway reserves.

(2) Price used when determining portions of bitumen reserves presented as In Situ and Mining reserves that are sold at the U.S. Gulf Coast, as well as for determining portions of bitumen pricing for royalty calculation purposes.

(3) Price used when determining portions of bitumen reserves presented as In Situ and Mining reserves that are sold in Canada, 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 for In Situ reserves and a ratio of approximately three barrels of bitumen for one barrel of diluent was used for Mining reserves. 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 presented as Offshore U.K. & Norway reserves.

(8) Prices for 2019 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			
2020	0.760	1.474	1.678
2021	0.770	1.474	1.656
2022	0.785	1.465	1.624
2023	0.785	1.465	1.624
2024	0.785	1.465	1.624
2025+	0.785	1.465	1.624

Disclosure of Net Present Values of Future Net Revenues After Income Taxes

Values presented in the table for Net Present Values of Future Net Revenues After Income Taxes reflect income tax burdens of assets at a business area or legal entity level 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 2019 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, 2019
(forecast prices and costs)

($ millions)	2020	2021	2022	2023	2024	Remainder	Total	Discounted At 10%
Proved								
Mining	1 553	2 279	2 559	2 602	2 028	19 000	30 021	15 909
In Situ	821	1 021	796	425	547	16 353	19 964	7 700
E&P Canada	286	149	119	41	57	222	875	727
Total Canada	2 660	3 449	3 475	3 068	2 633	35 576	50 860	24 336
Offshore U.K. & Norway	241	22	6	11	7	38	326	301
Total Proved	**2 901**	**3 471**	**3 481**	**3 079**	**2 640**	**35 613**	**51 186**	**24 637**
Proved Plus Probable								
Mining	1 768	2 622	3 003	3 184	2 562	26 731	39 870	19 182
In Situ	807	860	779	502	430	41 664	45 041	8 563
E&P Canada	730	408	414	278	197	828	2 856	2 263
Total Canada	3 305	3 890	4 196	3 964	3 189	69 224	87 767	30 008
Offshore U.K. & Norway	339	22	6	11	7	84	470	413
Total Proved Plus Probable	**3 644**	**3 912**	**4 202**	**3 975**	**3 196**	**69 307**	**88 237**	**30 421**

(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 2020 are expected to include:

- Mining development activities include capital investments expected to maintain the production capacity of existing facilities, including, but not limited to, tailings infrastructure, major maintenance, truck and shovel replacement, the replenishment of catalysts in hydrotreating units at the upgraders and improvements to utilities, roads and other facilities, and the implementation of technologies expected to reduce costs, including AHS.
- 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 of the WWRP, the Terra Nova ALE project, development drilling at Hibernia and Hebron.
- For E&P International, development of the Norwegian Fenja project, as well as development drilling at Buzzard.

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 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, 2019, Suncor estimated its undiscounted, uninflated abandonment and reclamation costs for its upstream assets to be approximately $12.7 billion (discounted at 10%, approximately $2.7 billion) excluding Refining and Marketing liabilities ($0.2 billion, undiscounted

and uninflated). Abandonment and reclamation costs are limited to current disturbances at December 31, 2019 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, 2019. Suncor estimates that it will incur $1.0 billion of its identified abandonment and reclamation costs during the next three years (undiscounted: 2020 – $0.5 billion, 2021 – $0.2 billion, 2022 – $0.2 billion), more than 82% 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 $26.9 billion (inflated and undiscounted) has been deducted as abandonment and reclamation costs in estimating the future net revenues from Proved Plus Probable reserves, including $23.6 billion related to the company's oil sands upgraders, extraction facilities, tailings ponds, subsurface wells and central processing facilities, which includes amounts related to current disturbances.

Gross Proved and Probable Undeveloped Reserves

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

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

	2017		2018		2019	
	First Attributed	Total as at December 31, 2017	First Attributed	Total as at December 31, 2018	**First Attributed**	**Total as at December 31, 2019**
SCO (mmbbls)						
Mining	—	—	—	—	**—**	**—**
In Situ	—	575	—	548	**53**	**627**
Total SCO	—	575	—	548	**53**	**627**
Bitumen (mmbbls)						
Mining	40	929	—	—	**—**	**—**
In Situ	—	675	—	653	**52**	**679**
Total Bitumen	40	1 603	—	653	**52**	**679**
Light Crude & Medium Crude Oil (mmbbls)						
E&P Canada	1	13	1	15	**2**	**16**
Offshore U.K. & Norway	—	—	8	8	**1**	**8**
Total Light Crude & Medium Crude Oil	1	13	9	23	**3**	**24**
Heavy Crude Oil (mmbbls)						
E&P Canada	—	34	—	46	**—**	**28**
Offshore U.K. & Norway	—	—	—	—	**—**	**—**
Total Heavy Crude Oil	—	34	—	46	**—**	**28**
Conventional Natural Gas (bcfe)						
E&P Canada	—	—	—	—	**—**	**—**
Offshore U.K. & Norway [2]	—	—	13	13	**—**	**13**
Total Conventional Natural Gas	—	—	13	13	**—**	**13**
Total (mmboe)	41	2 226	11	1 273	**108**	**1 359**

(1) Figures may not add due to rounding.

(2) Includes immaterial amounts of NGLs (less than 0.6 mmbbls).

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

	2017		2018		2019	
	First Attributed	Total as at December 31, 2017	First Attributed	Total as at December 31, 2018	**First Attributed**	**Total as at December 31, 2019**
SCO (mmbbls)						
Mining	—	282	26	308	—	**321**
In Situ	—	1 167	—	1 114	—	**1 070**
Total SCO	—	1 449	26	1 423	—	**1 391**
Bitumen (mmbbls)						
Mining	25	581	—	—	—	—
In Situ	—	275	—	330	—	**267**
Total Bitumen	25	856	—	330	—	**267**
Light Crude & Medium Crude Oil (mmbbls)						
E&P Canada	33	104	1	95	**6**	**96**
Offshore U.K. & Norway	2	12	8	9	**1**	**8**
Total Light Crude & Medium Crude Oil	34	116	9	104	**7**	**104**
Heavy Crude Oil (mmbbls)						
E&P Canada	—	73	—	28	—	**15**
Offshore U.K. & Norway	—	—	—	—	—	—
Total Heavy Crude Oil	—	73	—	28	—	**15**
Conventional Natural Gas (bcfe)						
E&P Canada	—	—	—	—	—	—
Offshore U.K. & Norway [2]	—	3	15	15	—	**15**
Total Conventional Natural Gas	—	3	15	15	—	**15**
Total (mmboe)	59	2 494	37	1 886	**7**	**1 780**

(1) Figures may not add due to rounding.

(2) Includes immaterial amounts of NGLs (less than 0.7 mmbbls).

Generally, Proved Undeveloped and Proved Plus Probable Undeveloped reserves are attributed based on the associated confidence levels required for Proved and Proved Plus Probable reserves, respectively, arising from the consideration of factors such as regulatory approvals, availability of markets and infrastructure, development timing, and technical aspects, and have been assigned in accordance with COGE Handbook guidelines. Probable reserves are calculated as the difference between Proved and Proved Plus Probable reserves.

In Situ

Undeveloped In Situ reserves, which constitute approximately 96% of Suncor's gross Proved Undeveloped reserves and 75% of Suncor's gross Probable Undeveloped reserves have been assigned to reserves areas which are not classified as Developed and are related only to those sustaining pads and well pairs required for current producing or sanctioned projects. 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, reserves have been drilled to a density of 16 delineation wells per section (i.e., 40-acre spacing), which is in excess of the eight delineation wells per section (80-acre spacing) required for regulatory approval. Further delineation is pursued through annual core hole drilling programs to refine development plans. Proved Undeveloped reserves have been assigned to areas delineated with vertical wells on 80-acre well spacing with 3D seismic control or 40-acre spacing without 3D seismic control. Probable Undeveloped areas are limited to areas delineated with vertical wells on 320-acre spacing with seismic control or 160-acre spacing without seismic control. Development of undeveloped In Situ reserves is an ongoing process and is a function of processing capacity and the forecasts of the declining production from existing In Situ wells. When production is forecast to decline, Suncor makes application for and, upon approval, commences development of the reserves and wells surrounding the declining areas. This entails drilling replacement well pairs and constructing sustaining pads and may take several years. Management uses integrated plans to forecast future Proved Undeveloped 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 updated and approved annually for internal and external factors affecting planned activity. The economic viability of developing sustaining pads and associated well pairs is tested to ensure that ongoing development is economic as required for reserves assessment.

Mining

Undeveloped Mining reserves constitute approximately 18% of Suncor's gross Probable Undeveloped reserves, and relate to the Syncrude MLX-W mining area, which is well-delineated by core hole drilling. The Syncrude MLX-W mining area received AER approval in 2019 and remaining approvals are expected in 2020.

E&P

Undeveloped conventional reserves (light crude oil and medium crude oil, heavy crude oil and natural gas) constitute approximately 4% of Suncor's gross Proved Undeveloped reserves and approximately 7% of Suncor's gross Probable Undeveloped reserves and 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, infill drilling in Buzzard and at the Fenja development project offshore Norway. Attribution of Proved Undeveloped and Probable Undeveloped reserves reflect, where applicable, the respective degrees of certainty with respect to various reservoir parameters, primarily drainage areas and recovery factors. In developing undeveloped conventional reserves, Suncor considers existing facility capacity, capital allocation plans, and remaining reserves availability. Suncor plans to proceed with development of essentially all Proved Undeveloped reserves within the next three years and with the development of all Probable Undeveloped reserves within the next five years.

Properties with no Attributed Reserves

The following table is a summary of properties to which no reserves are attributed as at December 31, 2019. 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	4 679 968	3 380 340
Libya	3 117 800	1 422 900
Syria	345 194	345 194
Norway	264 981	96 642
U.K.	54 589	20 034
Total	**8 462 532**	**5 265 110**

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 appraisal or even 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 2020, Suncor's rights to 61,261 net hectares in Canada, nil net hectares in Norway and 8,732 net hectares in the U.K. are scheduled to expire. The expiries include approximately 27,775 net hectares in In Situ and nil net hectares in Mining. Substantial portions of expiring lands may have their tenure continued beyond 2020 through the conduct of work programs and/or the payment of prescribed fees to the mineral 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 the company's oil and gas wells as at December 31, 2019.

	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]	408.0	408.0	34.0	34.0	—	—	—	—
Newfoundland and Labrador	86.0	21.5	6.0	1.7	—	—	—	—
Offshore U.K. & Norway	50.0	14.5	1.0	0.3	—	—	—	—
Other International[5]	—	—	419.0	211.1	—	—	6.0	6.0
Total	**544.0**	**444.0**	**460.0**	**247.1**	**—**	**—**	**6.0**	**6.0**

(1) Alberta oil wells and Other International oil and gas wells are onshore whereas Newfoundland and Labrador and Offshore U.K. & Norway wells are offshore.

(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 and multi-lateral wells are each counted as one well.

(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, if any, are associated with SAGD well pairs that have typically been drilled within the last three years, yet 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, 2019.

($ millions)	Exploration Costs	Proved Property Acquisition Costs	Unproved Property Acquisition Costs	Development Costs	Total
Canada – Mining and In Situ	204	—	—	3 580	3 784
Canada – E&P Canada	105	—	—	673	778
Total Canada	309	—	—	4 253	4 562
Offshore U.K. & Norway	135	—	—	319	454
Other International	8	—	—	—	8
Total	**452**	**—**	**—**	**4 572**	**5 024**

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, 2019.

	Exploratory Wells[1]		Development Wells	
Total number of wells completed	Gross	Net	Gross	Net
Canada – Oil Sands				
Oil	—	—	9.0	9.0
Service[2]	38.0	38.0	14.0	14.0
Stratigraphic Test[3]	223.0	223.0	783.0	539.7
Total	**261.0**	**261.0**	**806.0**	**562.7**
Canada – E&P Canada				
Oil	1.0	0.2	11.0	2.6
Dry Hole	1.0	0.3	—	—
Natural Gas	—	—	—	—
Service[2]	—	—	3.0	0.6
Stratigraphic Test	—	—	—	—
Total	**2.0**	**0.5**	**14.0**	**3.2**
Total Canada				
Oil	1.0	0.2	20.0	11.6
Dry Hole	1.0	0.3	—	—
Natural Gas	—	—	—	—
Service[2]	38.0	38.0	17.0	14.6
Stratigraphic Test	223.0	223.0	783.0	539.7
Total	**263.0**	**261.5**	**820.0**	**565.9**
Offshore U.K. & Norway				
Oil	2.0	0.5	4.0	1.2
Dry Hole	1.0	0.4	—	—
Service[2]	—	—	—	—
Stratigraphic Test	—	—	—	—
Total	**3.0**	**0.9**	**4.0**	**1.2**

(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 2019 included:

- For Mining, at Oil Sands Base development activities included turnaround and major maintenance at Upgrader 1, construction of fluid management facilities and utilities sustainment. At Fort Hills, development activities focused on completion of the remaining construction activities in secondary extraction. Other development activities for Fort Hills included advancing tailings infrastructure and procuring mobile equipment. At Syncrude, development activities included turnaround and reliability projects.

- 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 as well as provide future growth. Also included are stratigraphic test well drilling programs.

- For E&P Canada, drilling activities at Hebron, White Rose, Hibernia and Terra Nova, as well as development work on the WWRP. The drilling of one exploration well was also completed.

- For E&P International, development work on Buzzard and the Norwegian Oda and Fenja projects. The drilling of two exploration wells was also completed.

For significant exploration and development activities expected to occur in 2020 and beyond, refer to the Narrative Description of Suncor's Businesses and Additional Information Relating to Reserves Data – Future Development Costs sections in this AIF.

Production History[1]

2019	Q1	Q2	Q3	Q4	Year Ended
Canada – Oil Sands					
Total production (mbbls/d)	**657.2**	**692.2**	**670.0**	**662.3**	**670.4**
Oil Sands operations Bitumen (mbbls/d)	**55.4**	**118.7**	**105.2**	**118.1**	**99.5**
($/bbl)					
Average price realized[2]	41.59	48.26	42.21	36.73	42.08
Royalties	(1.37)	(2.96)	(1.98)	(1.23)	(1.94)
Production costs	(8.56)	(8.86)	(8.07)	(9.10)	(8.68)
Netback[4]	31.66	36.44	32.16	26.40	31.46
Oil Sands operations SCO and diesel (mbbls/d)	**341.2**	**295.5**	**317.0**	**300.0**	**313.3**
($/bbl)					
Average price realized[2]	64.90	74.97	68.11	70.93	69.65
Royalties	(1.38)	(2.98)	(2.17)	(2.02)	(2.13)
Production costs	(28.98)	(33.33)	(27.74)	(31.54)	(30.31)
Netback[4]	34.54	38.66	38.20	37.37	37.21
Fort Hills Bitumen (mbbls/d)	**78.4**	**89.3**	**85.5**	**87.9**	**85.3**
($/bbl)					
Average price realized[2]	49.95	57.10	48.50	41.41	48.96
Royalties	(1.43)	(1.27)	(1.70)	(1.10)	(1.37)
Production costs	(25.17)	(24.43)	(22.75)	(25.19)	(24.35)
Netback[4]	23.35	31.40	24.05	15.12	23.24
Syncrude SCO (mbbls/d)	**182.2**	**188.7**	**162.3**	**156.3**	**172.3**
($/bbl)					
Average price realized[2]	67.90	79.32	74.07	72.14	73.45
Royalties	(8.09)	(12.59)	(9.17)	(4.49)	(8.75)
Production costs	(31.53)	(28.73)	(33.80)	(32.65)	(31.56)
Netback[4]	28.28	38.00	31.10	35.00	33.14
Canada – Light Crude & Medium Crude Oil					
Total production (mbbls/d)	**58.3**	**61.9**	**49.6**	**69.6**	**59.9**
($/bbl)					
Average price realized[2]	84.60	90.48	79.39	84.36	84.86
Royalties	(19.75)	(13.65)	(6.54)	(13.46)	(13.62)

Production costs	(15.63)	(10.96)	(16.49)	(11.28)	(13.45)
Netback[4]	49.22	65.87	56.36	59.62	57.79
Offshore U.K. & Norway – Light Crude & Medium Crude Oil [3]					
Total production (mboe/d)	**47.1**	**47.2**	**40.6**	**43.6**	**44.6**
($/boe)					
Average price realized[2]	83.18	87.89	75.18	78.74	81.22
Royalties	—	—	—	—	—
Production costs	(5.09)	(7.08)	(5.29)	(8.30)	(6.45)
Netback[4][5]	78.09	80.81	69.89	70.42	74.77

(1) Production and liftings in Libya were intermittent in 2019 and not material to Suncor, and therefore are not included.

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

(3) Volumes include field production for immaterial amounts of associated gas and NGLs.

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

(5) Netback for Q4 and Year Ended includes sales from Oda, offshore Norway.

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, 2019.

	SCO	Bitumen	Light & Medium Oil
	mbbls/d	mbbls/d	mboe/d
Mining – Suncor	222.9	—	—
Mining – Syncrude	172.3	—	—
Mining – Fort Hills	—	85.3	—
Firebag	90.4	70.3	—
MacKay River	—	29.2	—
Buzzard	—	—	31.9
GEAD	—	—	9.0
Hibernia	—	—	20.1
White Rose	—	—	4.7
Terra Nova	—	—	11.6
Hebron	—	—	23.5

(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 2020 that are included in the estimates of Proved reserves and Probable reserves as at December 31, 2019.

	SCO (mbbls/d)[1]		Bitumen (mbbls/d)[1]		Light & Medium Crude Oil (mbbls/d)[1]		Conventional Natural Gas (mmcfe/d)[1][2]		Total (mboe/d)[1]	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Canada										
Proved	452	433	207	195	59	50	—	—	717	679
Probable	32	30	11	8	7	6	—	—	49	45
Proved Plus Probable	483	463	218	204	65	57	—	—	766	724
Offshore U.K. & Norway										
Proved	—	—	—	—	40	40	4	4	40	40
Probable	—	—	—	—	5	5	2	2	5	5
Proved Plus Probable	—	—	—	—	44	44	6	6	45	45
Total[1][2]										
Proved	452	433	207	195	98	90	4	4	757	719
Probable	32	30	11	8	11	11	2	2	54	50
Proved Plus Probable	483	463	218	204	110	101	6	6	811	769

(1) Figures may not add due to rounding.

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

The following properties each account for approximately 20% or more of total estimated production for 2020.

Proved

- From Millennium and North Steepbank: 222 mbbls/d of SCO, which represents approximately 29% of total estimated production for 2020.
- From Firebag: 168 mbbls/d of SCO and bitumen (79 mbbls/d and 89 mbbls/d, respectively), which represents approximately 22% of total estimated production for 2020.
- From Syncrude: 151 mbbls/d of SCO, which represents approximately 20% of total estimated production for 2020.

Proved Plus Probable

- From Millennium and North Steepbank: 235 mbbls/d of SCO, which represents approximately 29% of total estimated production for 2020.
- From Firebag: 180 mbbls/d of SCO and bitumen (84 mbbls/d and 96 mbbls/d, respectively), which represents approximately 22% of total estimated production for 2020.
- From Syncrude: 165 mbbls/d of SCO from Syncrude, which represents approximately 20% of total estimated production for 2020.

None of the company's Light & Medium Crude Oil production associated with its E&P Canada and Offshore U.K. & Norway assets accounts for 20% or more of the total estimated production for 2020.

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 to which it holds rights as at December 31, 2019. These commitments run through 2021 and beyond, and are primarily for conducting seismic programs and drilling exploration wells.

Country/Area ($ millions)	2020	2021	2022+	Total
Canada	—	—	—	—
Other International	—	—	499	499

Forward Contracts

Suncor may use financial derivatives to manage its exposure to fluctuations in commodity prices. A description of Suncor's use of such instruments is provided in the 2019 audited Consolidated Financial Statements and related MD&A for the year ended December 31, 2019.

Tax Horizon

In 2019, Suncor was subject to cash tax in the majority of the jurisdictions in which it generates earnings, including earnings related to its Canadian, U.S., U.K. and Libyan production. Based on projected future net earnings, Suncor is expected to be cash taxable on the majority of its earnings in 2020.

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 the 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 to legislation may be enacted. Suncor may engage in government consultation regarding proposed legislative changes to ensure Suncor's interests are recognized. The following discussion outlines some of the principal legislation, regulations and agreements that govern 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 Canada Energy Regulator (CER, formerly the National Energy Board). 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 CER approving such export.

In June 2019, Parliament adopted 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, established the CER and changed the energy regulatory regime. The changes resulting from Bill C-69 have not materially altered the previous requirements concerning 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.

Under the North American Free Trade Agreement (NAFTA), Canada is 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 by Canada relative to the total supply of goods exported by Canada 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); or (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.

In November 2018, Canada, the U.S. and Mexico signed the *Canada-United States-Mexico Agreement* (CUSMA) with a view to replacing NAFTA. Under CUSMA, Canada will no longer be subject to the proportionality provisions in NAFTA's energy chapter, which should permit the expansion of oil and gas exports beyond the U.S. In addition, CUSMA includes a change to the oil and gas rules of origin that will allow Canadian exporters to more easily qualify for duty-free treatment for shipments to the U.S. Canada must, however, notify the U.S. of its intention to enter free trade talks with any "non-market economies" under CUSMA, which may include China or other potential importers of Canadian oil and gas exports. Legislatures from each of the three countries must ratify CUSMA according to their own legislative processes before it goes into effect and replaces NAFTA. Legislation implementing the CUSMA was passed by the U.S. House of Representatives and the U.S. Senate on December 19, 2019 and January 16, 2020, respectively, and was signed into law by President Trump on January 29, 2020. In addition, CUSMA was ratified by the Senate of Mexico in June 2019, and will be formally ratified in that country when the President of Mexico announces ratification in the Federal Register of Mexico. Canada's implementation bill was introduced in May 2019 but will need to be re-introduced to Parliament. The timeline for ratification of CUSMA is currently uncertain in Canada.

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 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. 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.

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 2019 was 15% for active business income, including resource income. The average provincial income tax rate for Suncor in 2019 was approximately 11.74%.

On May 28, 2019, the Alberta government substantively enacted legislation to effect a staged reduction to the corporate income tax rate. The legislation decreases the corporate income tax rate from 12% to 8% as follows: 11% effective July 1, 2019, 10% effective January 1, 2020, 9% effective January 1, 2021 and 8% effective January 1, 2022. The reduction in the Alberta corporate income tax rate resulted in a reduction to Suncor's blended provincial income tax rate in 2019 as well as a $1.1 billion reduction to Suncor's consolidated deferred income tax liability.

Other Jurisdictions

Operations in the U.S. are subject to the U.S. federal tax rate of 21% and the effective rate for state taxes is approximately 1.6%, resulting in a total U.S. income tax rate of approximately 22.6%.

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, operations are subject to a tax rate of 78%.

Amounts presented in Suncor's 2019 audited Consolidated Financial Statements as royalties for production from the company's Libya operations are determined pursuant to EPSAs. The amounts calculated reflect the difference between Suncor's working interest in the particular project and the net revenue attributable to Suncor under the terms of the respective EPSAs. All government interests in these operations, except for income taxes, are presented as royalties.

Land Tenure

In Canada, crude oil and natural gas located in the western provinces are predominantly owned 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 the western provinces may also be privately owned, and rights to explore for and produce such oil and natural gas resources are granted pursuant to a private lease on the terms and conditions negotiated with the mineral rights holder. In central and eastern provinces 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 or territorial authorities, grants tenure in the form of exploration, significant discovery, and production licences.

In many other international jurisdictions, including the ones in which Suncor has operations, 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. Among other things, these environmental regulatory regimes impose restrictions and prohibitions on the spill, release or emission of various substances including oil and gas and the byproducts associated with the production thereof, which apply to Suncor and all other companies in the energy industry. Applicable 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, as well as the refining, distribution and marketing of petroleum products and petrochemicals. Environmental assessments and regulatory approvals are generally required before most new major projects or significant changes to existing operations can be initiated. In addition, these environmental regulatory regimes require the company to abandon and reclaim mine, well and facility sites to the satisfaction of regulatory authorities. In some cases, abandonment and reclamation obligations 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/or the imposition of material fines and penalties.

In addition to the specific requirements outlined above, Suncor anticipates that future amendments to environmental laws will result in the imposition of additional requirements on companies operating in the energy industry.

A number of statutes, regulations and governance frameworks pertaining to environmental regulation are currently under development and, in some cases, proposed amendments have been issued by the provincial regulators that oversee oil sands development for comment by industry. These statutes, regulations and frameworks relate to issues such as tailings management, water use, biodiversity, air emissions including methane emissions reduction, 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, the impact of current and future environmental laws and regulations on the company's business and operations, including laws and regulations relating to climate change, remains uncertain. It is not possible to predict the nature of any future legislative requirements, including those currently set out in the *Impact Assessment Act* and the *Canadian Energy Regulator Act*, 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, installing new emissions abatement equipment, investing in renewable forms of energy, such as wind power and biofuels, undertaking land reclamation activities, investing in environmentally focused 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 developments in environmental regulation and related government 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 where Suncor owns and operates assets.

As part of its ongoing business planning, Suncor estimates future costs associated with CO_2 emissions in its operations and in the evaluation of future projects. These estimates use the company's outlook for the carbon price under current and pending GHG regulations which are used in conjunction with other tools to test the company's business strategy against a range of policy designs. Currently, Suncor applies Provincial and Federal carbon regimes and a price of $30 per tonne of CO_{2e} which steadily increases to approximately $100 per tonne of CO_{2e} in 2040 as part of its base case evaluations. The company expects that GHG emissions regulation will continue to evolve with a carbon price that weighs economic, environmental and energy security objectives. Suncor will continue to review the impact of future carbon-constrained scenarios (and changing carbon pricing) on its business strategy.

Environmental regulations and initiatives related to climate change and GHG emissions are described below.

International Climate Change Agreements

The goals of the Paris Agreement on climate change, an agreement within the United Nations Framework Convention on Climate Change that came into force on November 4, 2016, are to prevent the global temperature rise from exceeding 2 degrees Celsius above pre-industrial levels 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. The federal government has also signalled its intentions to introduce legislation that will commit Canada to a net-zero emissions goal by 2050.

Canadian Federal GHG Regulations

Enacted and Effective

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 to meet Canada's emissions target while enabling economic growth.

Under the PCF, the federal government requires all provinces and territories to have a carbon price, starting at $20 per tonne of CO_{2e} in 2019 and rising by $10 per year to $50 per tonne of CO_{2e} in 2022. Jurisdictions can implement: (i) an explicit price-based system (such as the carbon tax adopted by British Columbia), (ii) the carbon levy and performance-based emissions system (adopted in Alberta), or (iii) cap-and-trade system (which has been adopted in Quebec). Within these programs, provinces have discretion to manage competitiveness of their energy intensive trade-exposed industries. The provincial carbon pricing initiatives applied in Alberta, British Columbia, Quebec, Ontario, and Newfoundland and Labrador and their impact on Suncor are described in the Canadian Provincial GHG Regulations section below.

The 2018 federal *Greenhouse Gas Pollution Pricing Act* (GGPPA) establishes the federal carbon price on GHG emissions applicable as of January 2019. The GGPPA reinforces the approach taken in the PCF and is only

intended to serve as a regulatory carbon pricing "backstop" to any province or territory that requests it, or to those jurisdictions that have not otherwise implemented a compliant provincial or territorial carbon pricing regime. The GGPPA consists of two parts: (1) an economy-wide consumer carbon levy on the use and combustion of fossil fuels; and (2) an Output Based Pricing System (OBPS) applied to heavy industrial sectors that face international competition.

Under Development

In addition to GGPPA's carbon pricing "backstop", a Clean Fuel Standard (CFS) is being developed by the federal government with the objective of achieving annual reductions of 30 Mt of CO_{2e} emissions by 2030. The CFS will be implemented under the *Canadian Environmental Protection Act* (CEPA). When implemented, it is expected that the CFS will require reductions in the carbon intensity of the fuels supplied into Canada, based on a new life cycle analysis model under development by the federal government. The approach is not expected to differentiate between crude oil produced in or imported into Canada. CFS is expected to apply to a broad suite of fuels used in transportation, industry, homes and buildings. The CFS regulations are being developed in stages, based on the class of fuel, and are expected to be finalized and enacted between 2022-23. Until such regulations are published, the company is unable to predict the impact, if any, that CFS will have on its business.

Canadian Provincial GHG Regulations

Alberta

Carbon Competitiveness Incentive Regulation (CCIR)

From January 1, 2018 until December 31, 2019, the applicable Alberta legislation was the CCIR. Under the CCIR, regulated facilities (which included Suncor's Oil Sands Base operations, Firebag, MacKay River, Fort Hills and the Edmonton refinery) were incented to reduce GHG emissions through improving performance by establishing product-based performance standards (also called output-based allocations) across all industries.

Suncor's compliance cost under the CCIR for the 2018 compliance year was $47 million in respect of its owned and operated properties. The 2018 compliance cost for Syncrude was $26 million, net to Suncor.

The 2019 compliance cost for all Suncor's owned and operated Alberta assets was $87 million and $21 million, net to Suncor, for Syncrude, respectively. Fort Hills remained exempt from compliance costs as a "new facility" under the CCIR until the end of 2019.

In addition to the regulations under the CCIR, the Alberta *Oil Sands Emissions Limit Act* (the OSELA) sets a limit of 100 Mt of CO_{2e} per 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 in Alberta are estimated to be 71 Mt per year, including existing upgrading capacity, but excluding cogenerated electricity sold to the Alberta power grid. The mechanics of implementation and enforcement of the OSELA remain under review by the Government of Alberta and, therefore, it is not yet possible to predict the long-term impact on Suncor.

Technology Innovation and Emissions Reduction Implementation Act (TIER)

On October 29, 2019, the Government of Alberta introduced TIER, which includes new carbon pricing legislation for large industrial emitters. TIER came into force on January 1, 2020, replacing CCIR. TIER meets the federal government's stringency benchmark criteria for large industrial emitters for 2020. As a result, the federal output-based carbon pricing system applicable to large industrial emitters, described under GGPPA, will not apply to Alberta. TIER applies to large industrial facilities in Alberta with CO_{2e} emissions in excess of 100,000 tonnes per year which, for Suncor, includes Oil Sands Base, Firebag, MacKay River, Fort Hills and the Edmonton refinery. Such facilities will be required to reduce emissions by 10% starting in 2020 with a further 1% per year reduction thereafter. Failure to meet emissions reduction targets results in being assessed at the prevailing carbon price. The carbon price under TIER will remain unchanged from the CCIR price of $30 per tonne of CO_{2e}.

Electricity generators will continue to be subject to the existing "good-as-best-gas" standard of 370 tonnes of CO_{2e} per GWh. Currently, Suncor's facilities are more efficient than the electricity standard and therefore earn credits.

Under TIER, each of Suncor's facilities is required to comply with the least stringent of either: (1) a facility-specific benchmark based on the average historical performance of that facility between 2013-15; or (2) a high-performance benchmark. All of Suncor's operations fall under the facility-specific benchmark. The high-performance benchmark is a product-specific, high-performance benchmark reflecting emissions intensity of high performance in a sector (calculated as average emissions intensity of the top 10% of facilities). Under TIER, facilities emitting over their prescribed benchmarks will be subject to a compliance obligation, while facilities emitting under their respective benchmarks will be able to generate Emissions Performance Credits (EPCs) and offset credits. Suncor will continue to generate such credits from its cogeneration and renewable energy assets.

Compared to CCIR, TIER is expected to result in lower compliance costs to Suncor. The 2020 estimated compliance cost for all of Suncor's owned and operated Alberta assets is $30 million, and $26 million, net to Suncor, for Syncrude.

Effective as of January 1, 2020, the federal fuel charge under GGPPA will apply to Alberta consumers as a $20 per tonne of CO_{2e} carbon levy on GHG emissions resulting from the combustion of fossil fuels for heating and transportation.

British Columbia

The Province of British Columbia enacted a consumption-based carbon tax in 2008. The purchasers or users of fuels pay the carbon tax, which is collected by Suncor and forwarded onto the government. The tax was $40 per tonne of CO_{2e} in 2019 and will rise to $45 per tonne of CO_{2e} in 2020 and $50 per tonne of CO_{2e} in 2021.

Quebec

Implemented in 2013, Quebec's cap and trade system for greenhouse gas emissions allowances applies to companies in the industrial and electricity sectors that emit 25,000 Mt or greater of CO_{2e} per year. Quebec's cap-and-trade system is linked to the Western Climate Initiative (WCI), an organization set up to help member states in the U.S. and Canadian 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 is subject to stationary emissions, and associated transportation end-users are subject to Quebec's cap-and-trade system.

For the 2018 and 2019 compliance years, the cost of compliance for the Montreal refinery was $1.2 million and $2 million, respectively. The 2020 estimated compliance cost attributed to the Montreal refinery's stationary emissions is $1.7 million. Compliance costs associated with end-user emissions arising from transportation fuels consumption are passed through to the customer at the time of purchase.

Ontario

Enacted and Effective

Effective January 1, 2018, Ontario formally launched its cap-and-trade system under WCI. Due to a change in government, the program was effectively cancelled July 3, 2018. This was finalized by the passage of Bill 4, *Cap and Trade Cancellation Act* effective October 31, 2018. As a result, Ontario became subject to the two-part federal government GGPPA program in 2019. Pursuant to the program, facilities that generate more than 25,000 tonnes of GHG emissions per year (including Suncor's Sarnia refinery and St. Clair ethanol plant) are subject to the Output Based Pricing System (OBPS). In addition, the federal carbon levy was applied to the combustion of all fossil fuels by consumers in Ontario. Similar to Quebec, costs attributed to the carbon levy on emissions from transportation fuels are passed through to the customer. Carbon prices pursuant to both aspects of the GGPPA program were $20 per tonne of CO_{2e} in 2019 and $30 per tonne of CO_{2e} in 2020.

For the 2018 and 2019 compliance year, the cost of compliance under the WCI and OBPS for the Sarnia refinery was $3.1 million and a credit of $0.43 million, respectively. For the St. Clair ethanol plant, the cost of compliance under the WCI and OBPS was nil and $0.75 million, respectively. The 2020 estimated compliance costs attributed to the Sarnia refinery and the St. Clair ethanol plant are nil and $1 million, respectively.

Under Development

Since the federal government's GGPPA program has been in place, the Government of Ontario has proposed an Emissions Performance Standards (EPS) that would be a "made in Ontario" carbon pricing system for large emitters. However, the federal government has indicated that Ontario will remain under the GGPPA program until the federal government conducts a countrywide review of provincial and territorial programs in 2022.

Newfoundland and Labrador

Enacted and Effective

Newfoundland and Labrador's carbon pricing program is a hybrid system comprised of performance standards for large industrial facilities, including large-scale electricity generation, plus a consumer carbon tax on transportation, building fuels, and other fuels combusted in the province. Performance standards for large industrial facilities are legislated under the *Management of Greenhouse Gas Act* (MGGA) and associated regulations, which apply to all facilities that emit 15,000 tonnes of CO_{2e} or more per annum and therefore applies to Terra Nova, Hibernia, White Rose, and Hebron. Consistent with the federal carbon pricing scheme, the Newfoundland and Labrador carbon price started in 2019 at $20 per tonne of CO_{2e} and increased to $30 per tonne of CO_{2e} for 2020.

For 2019, onshore facilities are assigned an annual GHG reduction target equal to 6% below the facility's 2016-17 historical average emissions-to-output ratio. The target increases by 2% per year until the reduction target reaches 12% in 2022. To protect the competitiveness of offshore petroleum facilities, each regulated facility will be assigned the same percentage reductions to its average emissions level, excluding federally regulated emissions for methane from venting and fugitive emissions. Consistent with the government's Advance 2030 initiative to encourage oil and gas development in the province, mobile offshore drilling unit activities related to exploration are exempt from the calculation for the unit's annual GHG reduction target.

The 2019 compliance cost attributed to the company's operated E&P Canada assets (Terra Nova), located offshore Newfoundland and Labrador, was $2.3 million. For 2020, the

forecast compliance cost is nil due to a planned maintenance turnaround program at Terra Nova.

Under Development

The MGGA also contemplates the establishment of a fund for energy efficient and 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 such as the province's offshore petroleum sector. Large industrial emitters, which include the offshore petroleum sector, account for approximately 43% of the province's current emissions.

U.S. GHG Regulations

Enacted and Effective

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.

In 2019, the State of Colorado passed a suite of energy and climate change related legislation that includes, but is not limited to, setting statewide targets to reduce 2025 GHG emissions by at least 26%; 2030 GHG emissions by 50%; and 2050 GHG emissions by 90%, using a 2005 baseline year. The legislation also includes rules to reduce emissions from the oil and gas sector, including the potential introduction of a low-carbon fuel standard, requirements to monitor, measure, report and forecast stationary emissions from large industrial facilities, and leak detection and repair as well as transitioning Colorado's electricity system to become 80% renewable by 2030 and 100% renewable by 2040. 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.

Under Development

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, with the current administration commencing formal proceedings to withdraw the U.S. from the Paris Agreement in November 2019. The current administration has also overturned a number of regulations promulgated by previous administrations intended to monitor or restrict climate change.

Notwithstanding the above, the United States Climate Alliance, a network consisting of the governors of 24 states, which include Colorado, remain committed to advancing efforts to address climate change through policies that encourage investment in clean energy, energy efficiency and climate resilience. Suncor continues to monitor these developments and constructively participate where appropriate.

International Regulations

The European Union Emissions Trading Scheme (EU ETS) applies to Suncor's non-operated offshore U.K. and Norway assets. 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 the area of the province in which Suncor's Oil Sands business is located. The LARP, which was developed pursuant to 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 established by LARP do not overlap with any of Suncor's or Syncrude's leases.

The management frameworks established under LARP formalize a number of regulatory tools used by the government to manage environmental aspects of oil sands development, including cumulative environmental effects of management on a regional scale. As a result, LARP may require Suncor and Syncrude to have greater participation in the overall evaluation of environmental issues and emissions in the Lower Athabasca region. The frameworks established under LARP include the following:

- **Air Quality Management Framework (AQMF).** The AQMF is designed to maintain flexibility and to manage the cumulative effects of development on air quality within the Lower Athabasca region, setting triggers and limits for nitrogen dioxide (NO_2) and sulphur dioxide (SO_2). The AQMF includes ambient air quality triggers and limits. Regulatory actions will occur when triggers or limits are reached or exceeded.

- **Surface Water Quality Management Framework (SWMF-Quality).** The SWMF-Quality provides a basis with which to monitor and manage long-term, cumulative changes in water quality within the Lower Athabasca River. The SWMF-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.

- **Surface Water Quantity Management Framework (SWMF-Quantity).** The SWMF-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 no more than their annual withdrawal licence average of 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 SWMF-Quantity requirements during low flow. To ensure that weekly flow triggers and cumulative water use limits for oil sands mining operators are met, each oil sands mining operator enters into an annual Oil Sands Water Management Sharing Agreement which is submitted to Fisheries and Oceans Canada and Alberta Environment and Parks. The agreement reduces the cumulative amount of water being withdrawn by oil sands mining operations when necessary to ensure that the cumulative water use limits established under SWQMF-Quantity are met.

- **Groundwater Management Framework (GMF).** The GMF aims to manage non-saline groundwater resources in a sustainable manner and protect groundwater 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.

- **Tailings Management Framework for Mineable Athabasca Oil Sands (TMF).** The TMF provides oil sands mining operations 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 tailings associated with oil sands mining and extraction. As a part of the implementation of the TMF, the AER finalized the Tailings Directive in October 2017. The Tailings Directive follows TMF guidance by requiring fluid tailings inventory triggers and a limit, as well as management actions such as a compliance levy and financial security through the Mine Financial Security Program (MFSP), to support the overarching 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, it is not possible to predict what impact financial management actions imposed pursuant to the Tailings Directive could have on Suncor at this time.

  Suncor is committed to reclaiming and remediating lands affected by its operations. 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 have been submitted and approved for Oil Sands Base (2017), Syncrude Aurora North (2018), Syncrude Mildred Lake (2019), and Fort Hills (2019).

  Another component identified in the TMF is integrated water management. In order to support successful closure and reclamation, water quantity must be reduced and quality must be managed.

Dam Integrity

The Government of Alberta has a rigorous and stringent regulatory system to manage dams within the province. In December 2018, the Water (Ministerial) Regulation was updated and includes new dam regulatory requirements. The primary purpose of these updates is to address regulatory requirements for in-stream dams (i.e., hydroelectric) requirements. However, these new requirements will also apply to all dams in Alberta, including off-stream dams (i.e., tailings dams).

Throughout 2019, the AER developed regulatory tools to provide guidance for how these new requirements apply to tailings facilities that are regulated by the AER, including oil sands tailings dams. The AER released *Manual 019: Decommissioning, Closure, and Abandonment of Dams at Energy Projects* (Manual 019) in January 2020, which explains how existing regulatory requirements pertaining to the decommissioning, closure, and abandonment of dams will be assessed and enforced by the AER rather than introducing any new requirements. These regulations are supplemented by Suncor's internal programs which are designed to provide additional oversight in accordance with industry best practices. The provincial dam integrity program may result in additional costs associated with monitoring, planning and measurements in addition to or in advance of current plans. Given the recent release of Manual 019, ongoing uncertainty about how the new regulations will apply to oil sands facilities may result in delay in regulatory approvals for facilities being reviewed under the new requirements.

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. Suncor has provided this security in the form of letters of credit and 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 between 2020 to 2023.

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 cost to the oil sands industry of enhanced monitoring under the Monitoring Plan has been estimated at approximately $50 million per year. The 2019 annual cost to Suncor under the Monitoring Plan is estimated to be approximately $11 million, including Suncor's net share of Syncrude compliance costs.

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, monitoring 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. The realization of any of the following risks could have a material adverse effect on Suncor's business, financial condition, reserves and results of operations.

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 and electricity prices in the company's upstream business where natural gas and power are both inputs and outputs 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 (particularly in emerging markets), market access constraints, regional and international supply and demand imbalances, political developments and government action (including the mandatory production curtailments recently imposed by the Government of Alberta), decisions by OPEC to not impose quotas on its members, compliance or non-compliance with quotas agreed upon by OPEC members and other countries, 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, market access, 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, reserves and results of operations.

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, reserves and results of operations.

In the fourth quarter of 2018, there was insufficient market access capacity to remove production from the Western Canada Sedimentary Basin causing the differential between WTI and WCS to widen significantly. The situation triggered a response from the Government of Alberta in the form of a mandatory production curtailment, which commenced in early 2019. Such circumstances may result in worsening and/or prolonged price volatility and/or further negative impacts on market dynamics that cannot currently be fully anticipated. Wide differentials, such as those experienced in the fourth quarter of 2018 or 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, reserves and results of operations, and may also lead to the impairment of assets, or to the cancellation or deferral of Suncor's growth projects.

Market Access

Suncor's production of bitumen is expected to grow. The markets for bitumen blends or heavy crude oil are more limited than those for light crude oil, 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.

Market access for Suncor's 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 could create widening differentials that could impact the profitability of product sales. Market access for refined products may also be constrained by insufficient takeaway capacity, which could create a supply/demand imbalance. 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.

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 and decommissioning of facilities, and carries the additional economic risk associated with operating reliably or enduring a protracted operational outage. The breadth and level of integration of Suncor's operations adds complexity.

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, delays in resuming normal operations, 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, prolonged periods of extreme cold or extreme heat, severe winter climate conditions, 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 (including information technology and related data and controls systems), and the environment.

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 the company's policies, standards and 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, network or cyber 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;

- Suncor's 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. Harsh weather conditions, particularly in the winter season, may also impact the successful execution of maintenance and startup of operations. Suncor's E&P offshore operations could be indirectly affected by catastrophic events occurring at other third-party offshore operations, which 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 comprehensive coverage in all circumstances, nor are all such risks insurable. The company self-insures some risks, and the company's insurance coverage does not cover all 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.

Government/Regulatory and Policy Effectiveness

Suncor's businesses operate under federal, provincial, territorial, state and municipal laws in numerous countries. The company 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 (including restrictions on production), 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, mine financial security requirements, approval of logistics infrastructure, and possibly expropriation or cancellation of contract rights. As part of ongoing operations, the company is also required to comply with a large number of EH&S regulations under a variety of Canadian, U.S., U.K., Norwegian 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 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, Indigenous and stakeholder consultation, environmental impact assessments and public hearings, government intervention and may be subject to conditions, including security deposit obligations and other commitments. 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, licences and approvals, or failure to obtain them on a timely basis or on satisfactory terms, could result in prosecution, fines, 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. 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.

Changes in government policy, 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 less profitable or 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 Indigenous consultation requirements as well as increased political involvement. The federal government's *Impact Assessment Act* (formerly Bill C-69) also came into force in August 2019 and will impact the manner in which large energy projects are approved. This development could also lead to significant delays and 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, permit approvals, and project development and execution, 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.

Suncor is subject to the mandatory production curtailments imposed by the Government of Alberta that commenced in early 2019. The duration, extent and consequences of the curtailments to Suncor's business are not fully known; however, prolonged production curtailment or changes to the curtailment levels could have a material adverse effect on Suncor's business, financial condition, reserves and results of operations.

Greenhouse Gas Emissions and Targets

Among other sustainability goals, Suncor has committed to reducing the total GHG emissions intensity of its oil and gas petroleum products by 30% by 2030 (based on a 2014 baseline year). Our ability to lower GHG emissions on both an absolute basis and in respect of our 2030 total emissions reduction target is subject to numerous risks and uncertainties and our actions taken in implementing these objectives may also expose us to certain additional and/or heightened financial and operational risks.

A reduction in GHG emissions relies on, among other things, our ability to implement and improve energy efficiency at all of our facilities, future development and growth opportunities, develop and deploy new technologies, invest in low-carbon power and transition to low-carbon fuels. In the event that we are unable to implement these strategies and technologies as planned without negatively impacting our expected operations or business plans, or in the event that such strategies or technologies do not perform as expected, we may be unable to meet our GHG targets or goals on the current timelines, or at all.

In addition, achieving our GHG emission reductions target and goals could require significant capital expenditures and resources, with the potential that the costs required to achieve our target and goals materially differ from our original estimates and expectations, which differences may be material. In addition, the shift in resources and focus towards emissions reduction could have a negative impact on our operating results. The overall final cost of investing in and implementing an emissions-intensity reduction strategy and technologies in furtherance of such strategy, and the resultant change in the deployment of our resources and focus, could have a material adverse effect on Suncor's business, financial condition, reserves 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, 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. Although current commodity pricing and increased regulatory requirements have slowed certain larger projects in the short term, an increase in the level of activity may have an impact on regional infrastructure, including pipelines, and could place 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, and impact demand for Suncor's products, which could have a material adverse effect on Suncor's business, financial condition and results of operations.

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, fossil fuel extraction, GHG emissions, and water and land-use practices 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.

Changes to environmental regulations, 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, abandonment and reclamation obligations and distribution costs, which may not be recoverable in the marketplace and which may result in current operations or growth projects becoming less profitable or 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 or obtain regulatory approvals for these technology projects could prevent Suncor from obtaining regulatory approvals for projects or being able to successfully compete with other companies. Increasing environmental regulation in the jurisdictions in which Suncor operates may also make it difficult for Suncor to compete with companies operating in other jurisdictions with fewer or less costly regulations. In addition, legislation or policies that limit the purchase of production from the oil sands may be adopted in domestic and/or foreign jurisdictions, which, in turn, may limit the world market for Suncor's upstream production and reduce the prices the company receives for its products, and could result in delayed development, stranded assets or the company being unable to further develop its resources. The complexity, breadth and velocity of changes in environmental regulation make it extremely difficult to predict the potential impact to Suncor.

Suncor continues to 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 may rise as a result of growth. 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, including litigation pertaining to GHG emissions, the production, sale, or promotion of fossil fuels and petroleum products, and/or disclosure. For example, the Board of County Commissioners of Boulder County, the Board of County Commissioners of San Miguel County and the City of Boulder, all of Colorado, have brought an action against Suncor and certain of its subsidiaries seeking, among other things, compensation for impacts they allege with respect 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. Refer to the Industry Conditions – Environmental Regulation – Climate Change – Canadian Provincial GHG Regulations (Alberta) section of this AIF.

These developments and future developments 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 and Water Release

Each oil sands mine is required under the Tailings Directive to seek approval for its updated fluid tailings management plans. If a mine fails to meet a condition of its approved plan, 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, the Tailings Directive and updates to the dam regulations including the financial consequences of exceeding compliance levels, is not yet fully known, as certain associated policy updates and regulation updates are still under development. Such updates could also restrict the technologies that the company may employ for tailings management, which could adversely impact the company's business plans. There could also be risks if the company's tailings management operations fail to operate as anticipated. The occurrence of any of the foregoing could have a material adverse effect on Suncor's business, financial condition, reserves and results of operations. Refer to the Industry Conditions – Environmental Regulation – Land Use and Dam Integrity section of this AIF.

In addition, an integrated water management approach to support operations and successful reclamation and closure requires the release of treated oil sands mine water to the environment, which is not currently permitted for oil sands mines under existing laws. There is no certainty as to when regulations authorizing such water release would be enacted, the content of any such regulations, and the ability of and timing for the company to obtain the required approvals under such regulations to permit such water release. The absence of effective government regulations in this area could impact the success and timing of closure and reclamation plans, which 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 a material 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 in a timely manner 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 obligated 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 Suncor operations and growth projects will 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.

Information Security

The efficient operation of Suncor's business is dependent on computer hardware, software and networked systems, including the systems of cloud providers and third parties with which Suncor conducts business. Digital transformation continues to increase the number of, and complexity of, such systems. In the ordinary course of Suncor's business, Suncor collects and stores sensitive data, including intellectual property, proprietary business information and 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. While Suncor has an information and cyber security program in place, the measures, controls and technology on which the company relies may not be adequate due to the increasing volume, sophistication and rapidly evolving nature 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, including natural disasters and acts of war. 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, physical harm to people or the environment or other negative consequences to Suncor or third parties, 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.

Security and Terrorist Threats

Security threats and terrorist or activist activities may impact Suncor's personnel, which could result in injury, death, extortion, hostage situations and/or kidnapping, including unlawful confinement. A security threat, terrorist attack or activist incident targeted at a facility or office owned or operated by Suncor could result in the interruption or cessation of key elements of Suncor's operations. Outcomes of such incidents could have a material adverse effect on Suncor's business, financial condition, reserves and results of operations.

Project Development and Execution

There are certain risks associated with the development and execution of Suncor's major projects and the commissioning and integration of new facilities within its existing asset base.

Project development and execution risk consists of four related primary risks:

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

Project development and execution can also be impacted by, among other things:

- The effect of changing government regulation and public expectations in relation to the impact of oil sands development on the environment, which could significantly impact the company's 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 complexity and diversity of Suncor's portfolio, including joint venture assets;
- The accuracy of project cost and schedule estimates, as actual costs and schedules for major projects can vary from estimates, and these differences can be material;
- The availability and cost of materials, equipment, qualified personnel, and logistics infrastructure, maintaining adequate quality management and risks associated with logistics and offshore fabrication, including the cost of materials, and equipment fabricated offshore may be impacted by tariffs, duties and quotas;
- The inability or unwillingness of third-party vendors, contractors or service providers to provide materials, equipment, personnel and services of necessary quality in the timelines anticipated and at the agreed upon cost;
- The complexities and uncertainties associated with identification, development and integration of new technologies into the company's existing and new assets;
- Complexities and risks associated with constructing projects within operating environments and confined construction areas;
- The commissioning and integration of new facilities within the company's existing asset base could cause delays in achieving guidance, targets and objectives;
- Risks relating to restarting projects placed in safe mode, including increased capital costs; and
- The impact of weather conditions.

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 sustainability, 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, or that third-party intellectual property protections may impede the development and implementation of new technology. 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.

Cumulative Impact and Pace 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. The establishment of the Transformation Management Office to support Suncor's digital transformation is expected to assist with the transformation, but there is still 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, reserves 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, In Situ assets, 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, scope, funding

and/or capital commitments with respect to projects that are being jointly developed.

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 manage its exposure to commodity price and other market risks, creates exposure to 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 2019 audited Consolidated Financial Statements are presented in Canadian dollars. The majority of Suncor's revenues from the sale of oil, natural gas and petroleum products 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 owes a portion of its debt in U.S. dollars. Suncor's financial 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, 2019, the Canadian dollar strengthened in relation to the U.S. dollar to $0.77 from $0.73 at the start of 2019. 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 credit 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 when derivative instruments are 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 and results of operations.

Issuance of Debt and Debt Covenants

Suncor expects that future capital expenditures will be financed out of cash and cash equivalents balances, cash flow provided by operating activities, available committed credit facilities, issuing commercial paper 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 and growth 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 by-laws limit the amount of indebtedness that may be incurred; however, Suncor is subject to covenants in its existing credit 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.

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, levies, tariffs, duties, quotas, 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.

Dividends and Share Repurchases

Suncor's payment of future dividends on its common shares and future share repurchases by Suncor of its common shares will be dependent on, among other things, legislative and stock exchange requirements, the company's financial condition, results of operations, cash flow, the need for funds to finance ongoing operations and growth projects, 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 or repurchase shares in the future.

E&P Reserves Replacement

Suncor's future offshore production, and therefore its cash flows and results of operations from E&P, are highly dependent upon success in exploiting its current reserves base and acquiring or discovering additional reserves. Without additions to its E&P reserves through exploration, acquisition or development activities, Suncor's production from its offshore assets will decline over time as reserves are depleted. The business of exploring for, developing or acquiring reserves is capital intensive. To the extent Suncor's cash flow is insufficient to fund capital expenditures and external sources of capital become limited or unavailable, Suncor's ability to make the necessary capital investments to maintain and expand its reserves will be impaired. In addition, Suncor may be unable to develop or acquire additional reserves to replace its crude oil and natural gas production at acceptable costs.

Uncertainties Affecting Reserves Estimates

There are numerous uncertainties inherent in estimating quantities of reserves, including many factors beyond the company's control. Suncor's actual production, revenues, royalties, taxes, and development and operating expenditures with respect to the company's reserves will vary from its estimates, and such variances could be material. Refer to the Statement of Reserves Data and Other Oil and Gas Information – Significant Risk Factors and Uncertainties Affecting Reserves section of this AIF.

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 or limited availability by one of these third parties can also have a dramatic impact on Suncor's operations and growth plans. 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.

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, such as that experienced in Libya and Syria, 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 its assets against terrorist activities or to remediate potential damage to its facilities. There can be no assurance that Suncor will be successful in protecting itself against these risks and the related safety and 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.

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 and changing skillsets as technology continues to evolve adds further pressure. The availability of competent and skilled contractors for current and future operations is also a risk depending on market conditions. 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 facilities (excluding MacKay River), all of the company's refineries, and the majority of the company's terminal and distribution operations are represented by labour unions or employee

associations. Approximately 31% of the company's employees were covered by collective agreements at the end of 2019. Negotiations for new collective agreements are in progress for two facilities across the company. Any work interruptions involving the company's employees (including as a result of a strike or lockout), 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.

Land Claims and Indigenous Consultation

Indigenous Peoples have claimed Indigenous title and rights to portions of Western Canada. In addition, Indigenous 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 Indigenous Peoples in respect of oil and gas projects and related infrastructure has also increased in recent years. In addition, in recent years, the Canadian federal government and the provincial government in Alberta have made a commitment to renew their relationships with the Indigenous 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". 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 Indigenous Peoples.

Suncor is unable to assess the effect, if any, that any such land claims, consultation requirements with Indigenous 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, disclosure, 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.

Trade Risk Relating to CUSMA

If CUSMA is ratified, Canada will no longer be subject to the proportionality provisions in NAFTA's energy chapter, enabling Canada to expand oil and gas exports beyond the U.S. Further, a change to the oil and gas rules of origin under CUSMA will allow Canadian exporters to more easily qualify for duty-free treatment for shipments to the U.S. Canada must, however, notify the U.S. of its intention to enter into free trade talks with any "non-market economies" under CUSMA, which may include China or any other importers of Canadian oil and gas exports. Although CUSMA has been signed, Canada has yet to ratify CUSMA according to its legislative processes before it goes into effect and replaces NAFTA. The outcome of the ratification process in Canada is not complete and is therefore uncertain. If CUSMA is not ratified and adopted by all three countries, the sale and transportation of Suncor's products within North America could be affected in a manner which could negatively impact Suncor's business, financial condition and results from operations.

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 how Suncor's business, financial condition and results of operations are reported.

Insurance Coverage

Suncor maintains insurance coverage as part of its risk management program. However, such insurance may not provide comprehensive coverage in all circumstances, nor are all such risks insurable. The company self-insures some risks, and the company's insurance coverage does not cover all the costs arising out of the allocation of liabilities and risk of loss arising from Suncor operations.

Suncor's insurance policies are generally renewed on an annual basis and, depending on factors such as market conditions, the premiums, policy limits and/or deductibles for certain insurance policies can vary substantially. In some instances, certain insurance may become unavailable or available only for reduced amounts of coverage. Significantly increased costs could lead the company to decide to reduce,

or possibly eliminate, coverage. In addition, insurance is purchased from a number of third-party insurers, often in layered insurance arrangements, some of whom may discontinue providing insurance coverage for their own policy or strategic reasons. Should any of these insurers refuse to continue to provide insurance coverage, the company's overall risk exposure could be increased.

DIVIDENDS

The Board of Directors has established a practice of paying dividends on Suncor's common shares 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 quarterly dividend of $0.32 per common share in each quarter of 2017, a quarterly dividend of $0.36 per common share in each quarter of 2018 and a quarterly dividend of $0.42 per common share in each quarter of 2019. Dividends are paid subject to applicable law, if, as and when declared by the Board.

Year ended December 31	**2019**	2018	2017
Cash dividends per common share ($)	**1.68**	1.44	1.28

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, 2019, there were 1,531,873,743 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, on a pro rata basis, 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 26, 2020. The credit ratings are not recommendations to purchase, hold or sell the debt securities in as much 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 at any time 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 Bal (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 on long-term debt are on a 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, 2019 are as follows:

TSX

	Price Range (Cdn$)		Trading Volume
	High	Low	(000s)
2019			
January	43.28	37.28	81 482
February	45.67	42.04	74 784
March	46.50	43.18	102 392
April	46.00	43.11	64 879
May	44.38	40.78	78 464
June	42.27	40.03	72 834
July	42.77	37.54	56 307
August	39.14	36.32	75 624
September	43.34	37.56	95 063
October	42.11	38.05	54 710
November	42.99	39.16	78 455
December	43.16	40.71	78 648

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 2019 audited Consolidated Financial Statements, which is incorporated by reference into this AIF and available on SEDAR at www.sedar.com.

DIRECTORS AND EXECUTIVE OFFICERS

Directors

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

Name and Jurisdiction of Residence	Period Served and Independence	Biography
Patricia M. Bedient[3][4] 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 to this, 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, Inc. 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 The 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 and corporate negotiations and is currently a director at Tectonic Metals Inc., a mineral exploration company. 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, and he has previously received the Indspire Award for Business.

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 Company. He is also 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[1][2] 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.

Mark Little Alberta, Canada	Director since 2019 Non-independent, management	Mark Little is president and chief executive officer of Suncor. He previously served as the company's president and chief operating officer before being appointed to his current position in May 2019. His past roles include serving as president of Suncor's upstream organization with responsibility for all of Suncor's operated and non-operated oil sands, in situ, conventional exploration and production assets worldwide, as well as executive vice president, Oil Sands and senior vice president, International and Offshore. Mr. Little was also senior vice president, Integration, following Suncor's merger with Petro-Canada and senior vice president, Strategic Growth and Energy Trading. In these roles, Mr. Little's accountabilities have spanned from operations in the Wood Buffalo region to operations in offshore East Coast Canada, the North Sea, and international onshore operations in Latin America, North Africa and the Near East, where he oversaw significant improvements in efficiency and performance, as well as portfolio growth. Before joining Suncor, Mr. Little led the development of oil sands projects for a major international energy company. His past experience also includes leadership roles in oil sands production and refining operations, strategic planning, environment, health and safety, and energy trading. Mr. Little has been active in industry and the community, serving as chair of the board of directors of Syncrude Canada and as a member of Energy Safety Canada until 2018. Mr. Little also was chair of the Oil Sands Safety Association prior to its merger into Energy Safety Canada. Having played an integral role in the signing of agreements with the Fort McKay and Mikisew Cree First Nations relating to Suncor's East Tank Farm, he has actively promoted the partnership as a model for future energy development with Indigenous communities. He is a current member of the Canadian Association of Petroleum Producers, where he also serves as a member of the Executive Committee and Oil Sands CEO Council. He has co-chaired the Canadian Council of Aboriginal Business' procurement initiative and is a past board member of Accenture Global Energy. Mr. Little holds degrees in both computer science from the University of Calgary and applied petroleum engineering technology from SAIT, and is a graduate of the advanced management program at Harvard Business School.

Brian MacDonald[3][4] Florida, U.S.	Director since 2018 Independent	Brian MacDonald was the president and chief executive officer of CDK Global, Inc., a leading global provider of integrated information technology and digital marketing solutions to the automotive retail and adjacent industries from 2016 to November 2018. Prior to joining CDK Global, Inc., Mr. MacDonald served as chief executive officer and president of Hertz Equipment Rental Corporation, and served as interim chief executive officer of Hertz Corporation. Mr. MacDonald previously served as president and chief executive officer of ETP Holdco Corporation, an entity formed following Energy Transfer Partners' $5.3 billion acquisition of Sunoco Inc., where Mr. MacDonald had served as chairman, president and chief executive officer. He was the chief financial officer at Sunoco Inc. and held senior financial roles at Dell Inc. Prior to Dell Inc., Mr. MacDonald spent more than 13 years in several financial management roles at General Motors Corporation in North America, Asia and Europe. He previously served on the board of directors for ComputerSciences Corporation (now DXC Technology Company), Ally Financial Inc., Sunoco Inc., Sunoco Logistics L.P. and CDK LGlobal, Inc. Mr. MacDonald earned a MBA from McGill University and a bachelor's of science, with a concentration in chemistry, from Mount Allison University.
Maureen McCaw[2][3] 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. Ms. McCaw currently serves as a director of the Francis Winspear Centre for Music and the Edmonton Symphony Orchestra and the Nature Conservancy of Canada. Ms. McCaw has previously served on a number of boards of directors including as chair of the CBC Pension Plan board of trustees, the Edmonton International Airport and the Edmonton Chamber of Commerce. Ms. Caw has also served on the board of directors of the Canadian Broadcasting Corporation. Ms. Caw holds a bachelor of arts degree in economics from the University of Alberta, completed Columbia Business School's executive program in financial accounting and earned an ICD.D certification from the Institute of Corporate Directors.

Lorraine Mitchelmore[2][3] Alberta, Canada	Director since 2019 Independent	Lorraine Mitchelmore has over 30 years' international oil and gas industry experience. She most recently served as President and CEO for Field Upgrading, a private equity backed fuel upgrading technology company. Prior to Field Upgrading, she held progressively senior roles at Royal Dutch Shell. Ms. Mitchelmore joined Shell in 2002, becoming President and Country Chair of Shell Canada Limited in 2009. Prior to joining Shell, she worked with Petro-Canada, Chevron and BHP Petroleum in the upstream business units in a combination of technical, exploration & development, and commercial roles. Ms. Mitchelmore has been a director of the Bank of Montreal since 2015 and has served on the Boards of Shell Canada Limited, the Canada Advisory Board at Catalyst, Inc. and Trans Mountain Corporation. Ms. Mitchelmore holds a bachelor's of science in geophysics from Memorial University of Newfoundland, a master's of science in geophysics from the University of Melbourne, Australia and a MBA from Kingston Business School in London, England.
Eira M. Thomas[1][4] Chiswick, United Kingdom	Director since 2006 Independent	Eira Thomas is a Canadian geologist with over 25 years of experience in the Canadian diamond business. She is currently the chief executive officer and a director of Lucara Diamond Corp., a publicly 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. Ms. Thomas graduated from the University of Toronto with a bachelor of science degree. Her awards and recognition include: "Canada's Top 40 under 40" by the Caldwell Partners and Report on Business magazine; selected as one of "Top 100 Canada's Most Powerful Women"; and one of only four Canadians in 2008 to be named to the "Young Global Leaders" by the World Economic Forum.
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

Executive Officers

The following individuals are the executive officers of Suncor:

Name	Jurisdiction of Residence	Office
Mark Little	Alberta, Canada	President and Chief Executive Officer
Alister Cowan	Alberta, Canada	Chief Financial Officer
Bruno Francoeur	Alberta, Canada	Chief Transformation Officer
Mike MacSween	Alberta, Canada	Executive Vice President, Upstream
Steve Reynish	Alberta, Canada	Executive Vice President, Strategy & Operations Services
Kris Smith	Alberta, Canada	Executive Vice President, Downstream
Martha Hall Findlay[(1)]	Alberta, Canada	Chief Sustainability Officer
Paul Gardner	Alberta, Canada	Chief People Officer
Arlene Strom	Alberta, Canada	Chief Legal Officer and General Counsel

(1) Effective January 6, 2020.

All executive officers have held positions with Suncor over the past five years with the exception of Martha Hall Findlay who, immediately prior to joining Suncor in 2019, was President and Chief Executive Officer of the Canada West Foundation.

As at February 21, 2020, the directors and executive officers of Suncor as a group beneficially owned, or controlled or directed, directly or indirectly, 398,419 common shares of Suncor, which represents 0.03% 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, that was issued 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: (i) 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, and (ii) Mr. Gass who was a director of Weatherford International plc (Weatherford) when it underwent a financial restructuring under chapter 11 of the U.S. Bankruptcy Code which was initiated on July 1, 2019. Mr. Gass ceased to be a director of Weatherford on December 13, 2019; 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, nor any shareholder holding a sufficient number of securities to affect materially the control of Suncor, has been subject to:

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

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

AUDIT COMMITTEE INFORMATION

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

Composition of the Audit Committee

The Audit Committee is comprised of Ms. Bedient (Chair), Mr. MacDonald, Ms. McCaw and Ms. Mitchelmore. 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 requirements of being an Audit Committee Financial Expert (as defined below) as determined in the judgment of the Board of Directors. The Audit Committee Financial Experts on the Audit Committee are Ms. Bedient and Mr. MacDonald.

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 practiced as a professional accountant, or the equivalent;
- Whether the person is certified or otherwise identified as having accounting or financial experience by a recognized private body that establishes and administers standards in respect of such expertise, whether that person is in good standing with the recognized private body, and the length of time that the person has been actively certified or identified as having this expertise;
- Whether the person has served as a principal financial officer, controller or principal accounting officer of a company 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) inclusive 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 securities laws, is attached as Schedule "B" to this AIF.

Fees Paid to Auditors

Fees paid or payable to the company's current auditors, KPMG LLP, in 2019 and to the company's predecessor auditors, PricewaterhouseCoopers LLP, in 2018 are as follows:

($ thousands)	**2019**	2018
Audit Fees	**4 350**	5 016
Audit-Related Fees	**410**	449
Tax Fees	**—**	—
All Other Fees	**—**	15
Total	**4 760**	5 480

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. All Other Fees were subscriptions to auditor-provided and supported tools. All services described beside the captions "Audit Fees", "Audit-Related 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, 2019, 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, 2019, (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, 2019.

INTERESTS 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, British Columbia, and Computershare Trust Company N.A. in Canton, Massachusetts, Jersey City, New Jersey and Louisville, Kentucky.

MATERIAL CONTRACTS

During the year ended December 31, 2019, 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 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, and none of the partners, employees or consultants of Sproule, 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.

Following the completion of a tender process in 2018, the Board (on the recommendation of the Audit Committee) approved the appointment of KPMG LLP as Suncor's auditor effective March 1, 2019. Pricewaterhouse Coopers LLP, the predecessor auditor, at the request of the company, resigned as auditor of the company effective March 1, 2019.

The company's independent auditors are KPMG LLP, Chartered Professional Accountants, who have issued an independent auditor's report dated February 26, 2020 in respect of the company's Consolidated Financial Statements, which comprise the Consolidated Balance Sheets as at December 31, 2019 and the Consolidated Statements of Comprehensive Income (Loss), Changes in Equity and Cash Flows for the year ended December 31, 2019, and the related notes, and the report on internal control over financial reporting as at December 31, 2019. KPMG 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).

The company's predecessor independent auditors were Pricewaterhouse Coopers LLP, who were the auditors for the company for the year ended December 31, 2018. As of February 28, 2019 and throughout the period covered by the financial statements upon which they reported, PricewaterhouseCoopers LLP were 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 SEC.

DISCLOSURE PURSUANT TO THE REQUIREMENTS OF THE NYSE

As a Canadian issuer listed on the NYSE, Suncor is not required to comply with most of the NYSE's governance 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 governance 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 2020 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 2019 audited Consolidated Financial Statements 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 Form 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 development and 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 projects, the performance of assets, production volumes, and capital expenditures, including:

- *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 mbbls/d, the expectation that major development activity will continue in 2020, that first oil is targeted for the end of 2022, and the expectation of an update from the project operator in the first half of 2020;*
- *Expectations about Oda, including proposed development plans and that peak production is expected to reach 35 mbbls/d (11 mbbls/d, net to Suncor);*
- *Expectations about the Forty Mile Wind Power Project, including the expectation that it will drive value through low-carbon power generation and retention of the generated carbon credits, the estimated total capital spend of $300 million with an expected completion date of late 2021 and the expectation that the first phase will consist of 45 4.5 MW wind turbines;*
- *Expectations about Hebron, including the expectation that, at peak, the project will produce 31.6 mbbls/d (net to Suncor) and the expectation that drilling activities will continue throughout 2020;*
- *Expectations about Suncor's coke-fired boiler replacement program, including the expectation that it will provide reliable steam generation, the expectation that it will reduce the GHG emissions intensity associated with steam production at Oil Sands Base operations by approximately 25% and the expectation that the project will cost approximately $1.4 billion with an expected in-service date in the second half of 2023;*
- *Expectations regarding Suncor's multi-year strategic alliance with Microsoft, including the expectation that this alliance will enable Suncor to utilize Microsoft's full range of cloud solutions and the expected benefits of the alliance;*
- *Suncor's expectation that it will file a regulatory application within the first quarter of 2020 to potentially replace Suncor's Millennium and North Steepbank mines and that a final sanctioning decision for this project is not expected until 2030 at the earliest;*
- *The belief that the opportunities identified by Suncor could potentially add up to an additional 30 mbbls/d above nameplate capacity;*
- *Expectations about the Meadow Creek East project, including the expectation that the project will be developed in two stages and the anticipated gross production from the project of 40 mbbls/d up to 80 mbbls/d;*
- *Expectations about the Meadow Creek West project, including the expectation that the project will be developed in a single stage, anticipated gross production capacity of the project of 40 mbbls/d;*
- *Expectations about the Lewis project, including that the project is expected to be developed in stages, with anticipated peak production of 160 mbbls/d;*
- *Expectations about Syncrude, including the expectation that the Syncrude joint venture partners' plan to develop MLX-W and MLX-E which, subject to approvals, 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, the plan to use existing mining and extraction facilities, the expectation that the remaining approvals will be obtained in 2020, efforts to achieve*

sustained reliability improvements and reduce costs at Syncrude, the opportunity for cost management and collaboration between the company and Syncrude, expectations for the bi-directional interconnecting pipelines between Syncrude's Mildred Lake site and Suncor's Oil Sands Base, including that the pipelines will provide increased operational flexibility through the ability to transfer bitumen and gas oils between the two plants, enabling higher reliability and utilization, the expectation that the pipelines will be in-service by the second half of 2020, and the expectation that sustaining capital expenditures in 2020 at Syncrude will focus on a planned turnaround and reliability improvements;

- *Expectations about Buzzard Phase 2, including that first oil is anticipated in early 2021, and that the development will be tied back to the existing Buzzard complex;*
- *Statements about the Terra Nova ALE, including the expectation that the project will extend the life of Terra Nova by approximately a decade, the timing of the project's execution and that the FPSO will be offline from April 2020 until approximately November 2020 while the ALE project is undertaken;*
- *Expectations about Rosebank, including timing of the sanction decision planned for 2022;*
- *Expectations about the Fenja development project, including the plan for development, first oil planned for 2021 and the expectation that peak production will be 34 mbbls/d (6 mbbls/d net to Suncor) and will be reached between 2021 and 2022;*
- *The estimated cost of Suncor's remaining exploration work program commitment in Libya at December 31, 2019 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;*
- *The expectation that turnaround maintenance will improve reliability and operational efficiency; and*
- *The expectation that capital investments with respect to Mining development activities will maintain the production capacity of existing facilities and reduce costs and that new well pairs and infill wells, at Firebag and MacKay River will maintain production levels in future years, as well as provide future growth.*

Also:

- *Expectations, goals and plans around technologies, including AHS, PASS, Zero-Impact Seismic and NAE, and expectations for the ISDF and partial upgrading;*
- *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 2020, 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 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 sustainability and to continuously optimize its asset portfolio and focus on core assets and ongoing balance sheet flexibility from the reduction of debt;*
- *Statements about Suncor's share repurchase program;*
- *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; Suncor's dependence on pipeline capacity and other logistical constraints, which may affect the company's ability to distribute products to market and which may cause the company to delay or cancel planned growth projects in the event of insufficient takeaway capacity; Suncor's ability to finance Oil Sands economic investment and asset sustainability and maintenance 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; 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; 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 development and execution of Suncor's projects and the commissioning and integration of new facilities; the possibility that completed maintenance activities may not improve operational performance or the output of related facilities; the risk that projects and initiatives intended to achieve cash flow growth and/or reductions in operating costs may not achieve the expected results in the time anticipated or at all; 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, tariffs, quotas and other government-imposed compliance costs and mandatory production curtailment orders and changes thereto; 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; security threats and terrorist or activist activities; the risk that competing business objectives may exceed Suncor's capacity to adopt and implement change; risks and uncertainties associated with obtaining regulatory, third-party and stakeholder approvals outside of Suncor's control for the company's operations, projects, initiatives, and exploration and development activities and the satisfaction of any conditions to approvals; 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; risks associated with land claims and Indigenous consultation requirements; the risk that the company may be subject 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 MD&A dated February 26, 2020 and Form 40-F on file with Canadian securities commissions at www.sedar.com and the SEC 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 similar measures presented by other companies and should not be considered in isolation or as a substitute for measures of performance prepared in accordance with GAAP. 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, 2019 and dated February 26, 2020.

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, 2019. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2019, 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, 2019, and identifies the respective portions thereof that we have evaluated and reported on to the Company's management and board of directors:

Independent Qualified Reserves Evaluator	Effective Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate, $ millions)			
			Audited	Evaluated	Reviewed	Total
GLJ Petroleum Consultants Ltd.	December 31, 2019	Oil Sands In Situ, Canada	—	25 850	—	25 850
GLJ Petroleum Consultants Ltd.	December 31, 2019	Oil Sands Mining, Canada	—	26 297	—	26 297
			—	52 147	—	52 147

6. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

7. We have no responsibility to update our reports referred to in paragraph 5 for events and circumstances occurring after the effective date of our reports.

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

EXECUTED as to our report referred to above:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, February 26, 2020

"Tim R. Freeborn"

Tim R. Freeborn, P.Eng.
Vice President and Chief Financial 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, 2019. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2019, 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, 2019, and identifies the respective portions thereof that we have evaluated and reported on to the Company's management and board of directors:

Independent Qualified Reserves Evaluator	Effective Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate, $ millions)			
			Audited	Evaluated	Reviewed	Total
Sproule Associates Limited	December 31, 2019	East Coast Canada, Newfoundland Offshore, Canada	—	7 134	—	7 134
Sproule International Limited	December 31, 2019	Offshore, United Kingdom	—	2 956	—	2 956
Sproule International Limited	December 31, 2019	Offshore, Norway	—	760	—	760
			—	10 849	—	10 849

6. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

7. We have no responsibility to update our reports referred to in paragraph 5 for events and circumstances occurring after the effective date of our reports.

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

EXECUTED as to our report referred to above:

Sproule Associates Limited and Sproule International Limited, Calgary, Alberta, Canada, February 26, 2020

"Cameron P. Six"

Cameron P. Six, P.Eng.
Chief Executive Officer

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.

"*Mark S. Little*"

MARK S. LITTLE
President and Chief Executive Officer

"*Alister Cowan*"

ALISTER COWAN
Chief Financial Officer

"*Michael M. Wilson*"

MICHAEL M. WILSON
Chair of the Board of Directors

"*Patricia M. Bedient*"

PATRICIA M. BEDIENT
Chair of the Audit Committee

February 26, 2020



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

201911-153

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 81 and 82 of Exhibit 99-1 and page 70 of Exhibit 99-2.

ATTESTATION REPORT OF THE REGISTERED PUBLIC ACCOUNTING FIRM

See pages 83 and 84 and 85 and 86 of Exhibit 99-1.

AUDIT COMMITTEE FINANCIAL EXPERT

See pages 80 and 81 of Annual Information Form.

CODE OF ETHICS

See pages 24 and 25 of Annual Information Form.

FEES PAID TO PRINCIPAL ACCOUNTANT

See page 81 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 53 of Exhibit 99-2.

TABULAR DISCLOSURE OF CONTRACTUAL OBLIGATIONS

See page 53 of Exhibit 99-2.

IDENTIFICATION OF THE AUDIT COMMITTEE

See page 80 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, 2019
99-2	Management's Discussion and Analysis for the fiscal year ended December 31, 2019, dated February 26, 2020
99-3	Consent of KPMG LLP
99-4	Consent of PricewaterhouseCoopers LLP
99-5	Consent of GLJ Petroleum Consultants Ltd.
99-6	Consent of Sproule Associates Limited and Sproule International Limited
99-7	Certificate of the Chief Executive Officer Pursuant to Exchange Act Rules 13a-14(a) or 15d-14(a)
99-8	Certificate of the Chief Financial Officer Pursuant to Exchange Act Rules 13a-14(a) or 15d-14(a)
99-9	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
99-10	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
99-11	Supplementary Oil and Gas Disclosures
101	Interactive data files with respect to the Annual Consolidated Financial Statements of Suncor Energy Inc. for the fiscal year ended December 31, 2019

SIGNATURES

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

SUNCOR ENERGY INC.

DATE: February 27, 2020

PER: /s/ ALISTER COWAN

Alister Cowan
Chief Financial Officer

QuickLinks

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UNDERTAKING AND CONSENT TO SERVICE OF PROCESS
DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROL OVER FINANCIAL REPORTING
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EXHIBIT 99-1

Audited Consolidated Financial Statements of Suncor Energy Inc. for the fiscal year ended December 31, 2019

MANAGEMENT'S STATEMENT OF RESPONSIBILITY FOR FINANCIAL REPORTING

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

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

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

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

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



Mark Little
President and Chief Executive Officer



Alister Cowan
Chief Financial Officer

February 26, 2020

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

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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

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

3. Management has assessed the effectiveness of the company's internal control over financial reporting as at December 31, 2019, and has concluded that such internal control over financial reporting was effective as of that date. In addition, based on this assessment, management determined that there were no material weaknesses in internal control over financial reporting as at December 31, 2019. Because of inherent limitations, systems of internal control over financial reporting may not prevent or detect misstatements and even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

4. The effectiveness of the company's internal control over financial reporting as at December 31, 2019 has been audited by KPMG LLP, independent auditor, as stated in their report which appears herein.



Mark Little
President and Chief Executive Officer



Alister Cowan
Chief Financial Officer

February 26, 2020

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and Board of Directors of Suncor Energy Inc.

Opinions on the Consolidated Financial Statements and Internal Control Over Financial Reporting

We have audited the accompanying consolidated balance sheet of Suncor Energy Inc. (the Company) as of December 31, 2019, the related consolidated statements of comprehensive income, changes in equity, and cash flows for the year then ended and the related notes (collectively, the consolidated financial statements). We also have audited the Company's internal control over financial reporting as of December 31, 2019, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2019, and the results of its operations and its cash flows for the year ended December 31, 2019, in conformity with International Financial Reporting Standards as issued by the International Accounting Standards Board. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2019 based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Change in Accounting Principle

As discussed in Note 5 to the consolidated financial statements, the Company has changed its method of accounting for leases as of January 1, 2019 due to the adoption of International Financial Reporting Standard 16 — *Leases*.

Comparative Information

As discussed in Note 6 of the consolidated financial statements, the 2018 segmented information has been restated to conform with the current year presentation. We have audited the adjustments as part of our audit of the consolidated financial statements as at and for the year ended December 31, 2019.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's consolidated financial statements and an opinion on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control Over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as

necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current period audit of the consolidated financial statements that were communicated or required to be communicated to the audit committee and that: (1) relate to accounts or disclosures that are material to the consolidated financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Evaluation of the assessment of indicators of impairment loss or reversal related to Oil Sands and Exploration and Production property, plant and equipment

As discussed in Note 15 to the consolidated financial statements, when circumstances indicate that a cash-generating unit ("CGU") may be impaired or a previous impairment reversed, the Company compares the carrying amount of the CGU to its recoverable amount. At each reporting date, the Company analyzes indicators of impairment loss or reversal ("impairment indicators"), such as significant increases or decreases in forecasted production volumes (which include assumptions related to proved and probable oil reserves), commodity prices, capital expenditures and operating costs (collectively, "reserve assumptions"). The estimate of reserve assumptions requires the expertise of reservoir engineering specialists. The Company engages independent reservoir engineering specialists to evaluate the Company's proved and probable oil reserves. The carrying amount of the Company's property, plant and equipment balance as of December 31, 2019 was $72,640 million.

We identified the evaluation of the assessment of impairment indicators related to the Oil Sands and Exploration and Production property, plant and equipment as a critical audit matter. A high degree of subjective auditor judgment was required to evaluate the reserve assumptions used by the Company in their assessment.

The primary procedures we performed to address this critical audit matter included the following. We tested certain internal controls over the Company's assessment of impairment indicators, including controls related to the reserve assumptions. We evaluated the Company's reserve assumptions by comparing the current year externally evaluated proved and probable oil reserves to historical results. We compared the Company's current year actual production volumes, operating costs and capital expenditures to those respective assumptions used in the prior year estimate of proved and probable reserves to assess the Company's ability to accurately forecast. We evaluated the Company's future commodity price estimates by comparing to a number of publicly available external price curves for the same benchmark pricing. We evaluated the competence, capabilities, and objectivity of the Company's independent reservoir engineering specialists engaged by the Company who evaluated proved and probable oil reserves. We evaluated the methodology used by the independent reservoir engineering specialists to evaluate proved and probable oil reserves for compliance with regulatory standards.

Assessment of the impairment of the Fort Hills and White Rose cash generating units

As discussed in note 15 to the consolidated financial statements, the Company recorded an impairment charge of $4,237 million related to the Fort Hills and White Rose cash generating units ("CGUs"). The Company identified an indicator of impairment at December 31, 2019 for both the Fort Hills and White Rose CGUs and performed impairment tests to determine the recoverable amount of the CGUs. The estimated recoverable amount of these CGUs involves numerous assumptions, including forecasted production volumes, commodity prices, operating costs, capital expenditures ("forecasted cash flow assumptions") and discount rates.

We identified the assessment of the impairment of the Fort Hills and White Rose CGUs as a critical audit matter. A high degree of subjective auditor judgment was required in evaluating the Company's forecasted cash flow and discount rate assumptions as minor changes to these assumptions have a significant effect on the Company's calculation of the recoverable amount of the CGUs. A high degree of subjective auditor judgement was also required to evaluate the externally evaluated proved and probable oil reserves which were used to assess the Company's forecasted cash flow assumptions.

The primary procedures we performed to address this critical audit matter included the following. We tested certain internal controls over the Company's determination of the recoverable amount of the CGUs being tested, including controls related to determination of the forecasted cash flow and discount rate assumptions. We performed sensitivity analyses over the discount rate and forecasted commodity price assumptions to assess their impact on the Company's determination of the recoverable amount for each CGU tested. We evaluated the Company's future commodity price estimates by comparing to a number of publicly available external price curves for the same benchmark pricing. We evaluated the forecasted production volumes, operating costs and capital expenditure assumptions used in the impairment test by comparing to the current year externally evaluated proved and probable oil reserves as well as to historical results. We assessed differences between management's forecasted cash flow assumptions and the externally evaluated proved and probable oil reserves by comparing to recent historical results. We compared the Company's current year actual production volumes, operating costs and capital expenditures to those assumptions used in the prior year externally evaluated proved and probable oil reserves to assess the Company's ability to accurately forecast. We evaluated the competence, capabilities and objectivity of the independent reservoir engineering specialists engaged by the Company, who evaluated the proved and probable oil reserves. We evaluated the methodology used by independent reservoir engineering specialists to estimate proved and probable oil reserves for compliance with regulatory standards. We involved a valuation professional with specialized skills and knowledge, who assisted in evaluating the Company's CGU discount rate assumptions, by comparing them against publicly available market data and other external data. The valuation professional estimated the recoverable amount of the CGUs using the estimate of the CGUs' forecasted cash flows and the discount rate evaluated by the specialist and compared the resulting recoverable amount to market and other external pricing data.



Chartered Professional Accountants

Calgary, Alberta, Canada

February 26, 2020

We have served as the Company's auditor since 2019.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and Board of Directors of Suncor Energy Inc.

Opinion on the Consolidated Financial Statements

We have audited the Consolidated Balance Sheet of Suncor Energy Inc. and its subsidiaries (together, the "Company") as of December 31, 2018, and the related Consolidated Statements of Comprehensive Income, Changes in Equity and Cash Flows for the year then ended, including the related notes (collectively referred to as the Consolidated Financial Statements) before the effects of the adjustments to retrospectively restate and reallocate segmented results as described in Note 6.

In our opinion, the Consolidated Financial Statements, before the effects of the adjustments to retrospectively restate and reallocate segmented results as described in Note 6, present fairly, in all material respects, the financial position of the Company as of December 31, 2018, and the results of operations and cash flows for the year ended December 31, 2018, in conformity with International Financial Reporting Standards as issued by the International Accounting Standards Board ("IFRS") (the 2018 financial statements before the effects of the adjustments discussed in Note 6 are not presented herein).

We were not engaged to audit, review, or apply any procedures to the adjustments to retrospectively restate and reallocate segmented results as described in Note 6 and accordingly, we do not express an opinion or any other form of assurance about whether such adjustments are appropriate and have been properly applied. Those adjustments were audited by other auditors.

Basis for Opinion

These Consolidated Financial Statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's Consolidated Financial Statements, before the effects of the adjustments described above, based on our audit. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit of these Consolidated Financial Statements, before the effects of the adjustments described above, in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the Consolidated Financial Statements are free of material misstatement, whether due to error or fraud.

Our audit included performing procedures to assess the risks of material misstatement of the Consolidated Financial Statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the Consolidated Financial Statements. Our audit also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the Consolidated Financial Statements. We believe that our audit provides a reasonable basis for our opinion.



Chartered Professional Accountants

Calgary, Alberta, Canada

February 28, 2019

We served as the Company's auditor from 1972 to 2019.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

For the years ended December 31 ($ millions)	Notes	2019	2018
Revenues and Other Income			
Operating revenues, net of royalties	6	**38 344**	38 542
Other income	7	**645**	444
		38 989	38 986
Expenses			
Purchases of crude oil and products		**12 562**	14 133
Operating, selling and general	8 and 25	**11 244**	10 573
Transportation		**1 442**	1 319
Depreciation, depletion, amortization and impairment	15	**10 572**	5 738
Exploration		**256**	122
Gain on asset exchange and disposals	34	**(253)**	(24)
Financing expenses	9	**633**	2 142
		36 456	34 003
Earnings before Income Taxes		**2 533**	4 983
Income Tax (Recovery) Expense	10		
Current		**1 552**	1 250
Deferred	10 and 15	**(1 918)**	440
		(366)	1 690
Net Earnings		**2 899**	3 293
Other Comprehensive (Loss) Income			
Items That May be Subsequently Reclassified to Earnings:			
Foreign currency translation adjustment		**(177)**	267
Items That Will Not be Reclassified to Earnings:			
Actuarial (loss) gain on employee retirement benefit plans, net of income taxes		**(48)**	103
Other Comprehensive (Loss) Income		**(225)**	370
Total Comprehensive Income		**2 674**	3 663
Per Common Share (dollars)	11		
Net earnings – basic		**1.86**	2.03
Net earnings – diluted		**1.86**	2.02
Cash dividends		**1.68**	1.44

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

CONSOLIDATED BALANCE SHEETS

($ millions)	Notes	December 31 2019	December 31 2018
Assets			
Current assets			
Cash and cash equivalents	12	**1 960**	2 221
Accounts receivable		**4 052**	3 206
Inventories	14	**3 761**	3 159
Income taxes receivable		**133**	114
Total current assets		**9 906**	8 700
Property, plant and equipment, net	5, 15, 16, 33 and 34	**72 640**	74 245
Exploration and evaluation	17	**2 428**	2 319
Other assets	18	**1 194**	1 126
Goodwill and other intangible assets	19	**3 058**	3 061
Deferred income taxes	10	**209**	128
Total assets		**89 435**	89 579
Liabilities and Shareholders' Equity			
Current liabilities			
Short-term debt	20	**2 155**	3 231
Current portion of long-term debt	20	**—**	229
Current portion of long-term lease liabilities	5	**310**	—
Accounts payable and accrued liabilities		**6 555**	5 647
Current portion of provisions	23	**631**	667
Income taxes payable		**886**	535
Total current liabilities		**10 537**	10 309
Long-term debt	20	**12 884**	13 890
Long-term lease liabilities	5	**2 621**	—
Other long-term liabilities	21	**2 499**	2 346
Provisions	23	**8 676**	6 984
Deferred income taxes	10 and 15	**10 176**	12 045
Equity		**42 042**	44 005
Total liabilities and shareholders' equity		**89 435**	89 579

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

Approved on behalf of the Board of Directors:





Mark Little
Director

Patricia M. Bedient
Director

February 26, 2020

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the years ended December 31 ($ millions)	Notes	2019	2018
Operating Activities			
Net earnings		**2 899**	3 293
Adjustments for:			
Depreciation, depletion, amortization and impairment		**10 572**	5 738
Deferred income tax (recovery) expense	10 and 15	**(1 918)**	440
Accretion		**270**	266
Unrealized foreign exchange (gain) loss on U.S. dollar denominated debt		**(624)**	1 090
Change in fair value of financial instruments and trading inventory		**107**	(179)
Gain on asset exchange and disposals	34	**(253)**	(24)
Share-based compensation		**44**	(117)
Exploration		**66**	11
Settlement of decommissioning and restoration liabilities		**(464)**	(469)
Other		**119**	123
(Increase) decrease in non-cash working capital	13	**(397)**	408
Cash flow provided by operating activities		**10 421**	10 580
Investing Activities			
Capital and exploration expenditures		**(5 558)**	(5 406)
Acquisitions	32 to 34	**—**	(1 230)
Proceeds from disposal of assets		**274**	84
Other investments	34	**(213)**	(170)
Decrease in non-cash working capital	13	**409**	25
Cash flow used in investing activities		**(5 088)**	(6 697)
Financing Activities			
Net (decrease) increase in short-term debt		**(982)**	866
Net increase (decrease) in long-term debt	20	**557**	(186)
Lease liability payments	5	**(307)**	—
Issuance of common shares under share option plans		**90**	286
Purchase of common shares	24	**(2 274)**	(3 053)
Distributions relating to non-controlling interest		**(7)**	(6)
Dividends paid on common shares		**(2 614)**	(2 333)
Cash flow used in financing activities		**(5 537)**	(4 426)
Decrease in Cash and Cash Equivalents		**(204)**	(543)

Effect of foreign exchange on cash and cash equivalents	**(57)**	92
Cash and cash equivalents at beginning of year	**2 221**	2 672
Cash and Cash Equivalents at End of Year	**1 960**	2 221

Supplementary Cash Flow Information

Interest paid	**996**	800
Income taxes paid	**1 033**	645

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

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

($ millions)	Notes	Share Capital	Contributed Surplus	Accumulated Other Comprehensive Income	Retained Earnings	Total	Number of Common Shares (thousands)
At December 31, 2017		26 606	567	809	17 401	45 383	1 640 983
Net earnings		—	—	—	3 293	3 293	—
Foreign currency translation adjustment		—	—	267	—	267	—
Actuarial gain on employee retirement benefit plans, net of income taxes of $39	22	—	—	—	103	103	—
Total comprehensive income		—	—	267	3 396	3 663	—
Issued under share option plans		358	(73)	—	—	285	7 927
Purchase of common shares for cancellation	24	(1 040)	—	—	(2 013)	(3 053)	(64 426)
Change in liability for share purchase commitment	24	(14)	—	—	28	14	—
Share-based compensation	25	—	46	—	—	46	—
Dividends paid on common shares		—	—	—	(2 333)	(2 333)	—
At December 31, 2018		25 910	540	1 076	16 479	44 005	1 584 484
At January 1, 2019		**25 910**	**540**	**1 076**	**16 479**	**44 005**	**1 584 484**
Adoption of IFRS 16 impact	5	**—**	**—**	**—**	**14**	**14**	**—**
At January 1, 2019, adjusted		**25 910**	**540**	**1 076**	**16 493**	**44 019**	**1 584 484**
Net earnings		**—**	**—**	**—**	**2 899**	**2 899**	**—**
Foreign currency translation adjustment		**—**	**—**	**(177)**	**—**	**(177)**	**—**
Actuarial loss on employee retirement benefit plans, net of income taxes of $23	22	**—**	**—**	**—**	**(48)**	**(48)**	**—**
Total comprehensive (loss) income		**—**	**—**	**(177)**	**2 851**	**2 674**	**—**
Issued under share option plans		**116**	**(24)**	**—**	**—**	**92**	**2 688**
Purchase of common shares for cancellation	24	**(905)**	**—**	**—**	**(1 369)**	**(2 274)**	**(55 298)**
Change in liability for share purchase commitment	24	**46**	**—**	**—**	**49**	**95**	**—**
Share-based compensation	25	**—**	**50**	**—**	**—**	**50**	**—**
Dividends paid on common shares		**—**	**—**	**—**	**(2 614)**	**(2 614)**	**—**
At December 31, 2019		**25 167**	**566**	**899**	**15 410**	**42 042**	**1 531 874**

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

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. REPORTING ENTITY AND DESCRIPTION OF THE BUSINESS

Suncor Energy Inc. (Suncor or the company) is an integrated energy company headquartered in Calgary, Alberta, Canada. Suncor is strategically focused on developing one of the world's largest petroleum resource basins – Canada's Athabasca oil sands. In addition, the company explores for, acquires, develops, produces, transports, refines and markets crude oil in Canada and internationally, Suncor markets petroleum and petrochemical products primarily in Canada, under the Petro-Canada® brand. The company also operates a renewable energy business and conducts energy trading activities focused principally in the marketing and trading of crude oil, natural gas, byproducts, refined products, and power.

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

2. BASIS OF PREPARATION

(a) Statement of Compliance

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

Suncor's accounting policies are based on IFRS issued and outstanding for all periods presented in these consolidated financial statements. These consolidated financial statements were approved by the Board of Directors on February 26, 2020.

(b) Basis of Measurement

The consolidated financial statements are prepared on a historical cost basis except as detailed in the accounting policies disclosed in note 3. The accounting policies described in note 3 have been applied consistently to all periods presented in these consolidated financial statements with the exception of IFRS 16 *Leases*. Refer to note 5.

(c) Functional Currency and Presentation Currency

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

(d) Use of Estimates, Assumptions and Judgments

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

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

(a) Principles of Consolidation

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

(b) Joint Arrangements

Joint arrangements represent arrangements in which two or more parties have joint control established by a contractual agreement. Joint control only exists when decisions about the activities that most significantly affect the returns of the investee are unanimous. Joint arrangements can be classified as either a joint operation or a joint venture. The classification of joint arrangements requires judgment. In determining the classification of its joint arrangements, the company considers the contractual rights and obligations of each investor and whether the legal structure of the joint arrangement gives the entity direct rights to the assets and obligations for the liabilities.

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

Where the company has rights to the net assets of an arrangement, the arrangement is classified as a joint venture and accounted for using the equity method of accounting. Under the equity method, the company's initial investment is

recognized at cost and subsequently adjusted for the company's share of the joint venture's income or loss, less distributions received.

(c) Foreign Currency Translation

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

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

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

(d) Revenues

Revenue from the sale of crude oil, natural gas, natural gas liquids, purchased products, refined petroleum products and power represent the company's contractual arrangements with customers. Revenue is recorded when control passes to the customer, in accordance with specified contract terms. All operating revenue is earned at a point in time and is based on the consideration that the company expects to receive for the transfer of the goods to the customer. Revenues are usually collected in the month following delivery except retail gasoline, diesel and ancillary products which are due upon delivery and, accordingly, the company doesn't adjust consideration for the effects of a financing component.

Revenue from oil and natural gas production is recorded net of royalty expense.

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

(e) Cash and Cash Equivalents

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

(f) Inventories

Inventories of crude oil and refined products, other than inventories held for trading purposes, are valued at the lower of cost, using the first-in, first-out method, and net realizable value. Cost of inventory consists of purchase costs, direct production costs, direct overhead and depreciation, depletion and amortization. Materials and supplies are valued at the lower of average cost and net realizable value.

Inventories held for trading purposes are carried at fair value less costs of disposal, and any changes in fair value are recognized in Other Income within the respective reporting segment to which the trading activity relates.

(g) Assets Held for Sale

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

(h) Exploration and Evaluation Assets

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

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

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

(i) Property, Plant and Equipment

Property, Plant and Equipment are initially recorded at cost.

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

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

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

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

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

(j) Depreciation, Depletion and Amortization

Exploration and Evaluation assets are not subject to depreciation, depletion and amortization. Once transferred to oil and gas properties within Property, Plant and Equipment and commercial production commences, these costs are depleted on a unit-of-production basis over proved developed reserves, with the exception of exploration and evaluation costs associated with oil sands mines, which are depreciated on a straight-line basis over the life of the mine, and property acquisition costs, which are depleted over proved reserves.

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

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

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

Oil sands upgraders, extraction plants and mine facilities	20 to 40 years
Oil sands mine equipment	5 to 15 years
Oil sands in situ processing facilities	30 years
Power generation and utility plants	30 to 40 years
Refineries and other processing plants	20 to 40 years
Marketing and other distribution assets	10 to 40 years

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

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

Right-of-use assets within Property, Plant and Equipment are depreciated on a straight-line basis over the shorter of the estimated useful life of the right-of-use asset or the lease term.

(k) Goodwill and Other Intangible Assets

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

Other intangible assets include acquired customer lists and brand value.

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

(l) Impairment of Assets

Non-Financial Assets

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

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

Impairments may be reversed for all CGUs and individual assets, other than goodwill, if there has been a change in the estimates and judgments used to determine the asset's recoverable amount. If such indication exists, the carrying amount of the CGU or asset is increased to its revised recoverable amount, which cannot exceed the carrying amount that would have been determined, net of depletion, depreciation and amortization, had no impairment been recognized.

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

Financial Assets

At each reporting date, the company assesses whether there is evidence indicating that financial assets measured at amortized cost may be impaired. If a financial asset measured at amortized cost is determined to be impaired, the impairment is recognized in Operating, Selling and General expense.

(m) Provisions

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

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

(n) Income Taxes

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

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

(o) Pensions and Other Post-Retirement Benefits

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

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

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

(p) Share-Based Compensation Plans

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

Share-based compensation awards that settle in cash or have the option to settle in cash or shares are accounted for as cash-settled plans. These are measured at fair value each reporting period using the Black-Scholes options pricing model. The expense is recognized over the vesting period, with a corresponding adjustment to the outstanding liability. When awards are surrendered for cash, the cash settlement paid reduces the outstanding liability. When awards are exercised for common shares, consideration paid by the holder and the previously recognized liability associated with the options are recorded to Share Capital.

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

(q) Financial Instruments

The company classifies its financial instruments into one of the following categories: fair value through profit or loss (FVTPL), fair value through other comprehensive income, or at amortized cost. This determination is made at initial recognition. All

financial instruments are initially recognized at fair value on the balance sheet, net of any transaction costs except for financial instruments classified as FVTPL, where transaction costs are expensed as incurred. Subsequent measurement of financial instruments is based on their classification. The company classifies its derivative financial instruments as FVTPL, cash and cash equivalents and accounts receivable as financial assets at amortized cost, and accounts payable and accrued liabilities, debt, and other long-term liabilities as financial liabilities at amortized cost.

In circumstances where the company consolidates a subsidiary in which there are other owners with a non-controlling interest and the subsidiary has a non-discretionary obligation to distribute cash based on a predetermined formula to the non-controlling owners, the non-controlling interest is classified as a financial liability rather than equity in accordance with IAS 32 *Financial Instruments: Presentation*. The non-controlling interest liability is classified as an amortized cost liability and is presented within Other Long-Term Liabilities. The balance is accreted based on current period interest expense recorded using the effective interest method and decreased based on distributions made to the non-controlling owners.

The company uses derivative financial instruments, such as physical and financial contracts, either to manage certain exposures to fluctuations in interest rates, commodity prices and foreign exchange rates, as part of its overall risk management program. Earnings impacts from derivatives used to manage a particular risk are reported as part of Other Income in the related reporting segment.

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

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

(r) Hedging Activities

The company may apply hedge accounting to arrangements that qualify for designated hedge accounting treatment. Documentation is prepared at the inception of a hedge relationship in order to qualify for hedge accounting. Designated hedges are assessed at each reporting date to determine if the relationship between the derivative and the underlying hedged item accomplishes the company's risk management objectives for financial and non-financial risk exposures.

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

The company did not apply hedge accounting to any of its derivative instruments for the years ended December 31, 2019 or 2018.

(s) Share Capital

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

(t) Dividend Distributions

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

(u) Earnings per Share

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

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

(v) Emissions Obligations

Emissions obligations are measured at the weighted average cost per unit of emissions expected to be incurred in the compliance period and are recorded in the period in which the emissions occur within Operating, Selling and General expense.

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

4. SIGNIFICANT ACCOUNTING ESTIMATES AND JUDGMENTS

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

Oil and Gas Reserves

The company's estimate of oil and gas reserves is considered in the measurement of depletion, depreciation, impairment, and decommissioning and restoration obligations. The estimation of reserves is an inherently complex process and involves the exercise of professional judgment. All reserves have been evaluated at December 31, 2019 by independent qualified reserves evaluators. Oil and gas reserves estimates are based on a range of geological, technical and economic factors, including projected future rates of production, projected future commodity prices, engineering data, and the timing and amount of future expenditures, all of which are subject to uncertainty. Estimates reflect market and regulatory conditions existing at December 31, 2019, which could differ significantly from other points in time throughout the year, or future periods. Changes in market and regulatory conditions and assumptions can materially impact the estimation of net reserves.

Oil and Gas Activities

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

Exploration and Evaluation Costs

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

Determination of Cash Generating Units (CGUs)

A CGU is the lowest grouping of integrated assets that generate identifiable cash inflows that are largely independent of the cash inflows of other assets or groups of assets. The allocation of assets into CGUs requires significant judgment and interpretations with respect to the integration between assets, the existence of active markets, similar exposure to market risks, shared infrastructure, and the way in which management monitors the operations.

Asset Impairment and Reversals

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

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

Decommissioning and Restoration Costs

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

Actual costs are uncertain and estimates may vary as a result of changes to relevant laws and regulations related to the use of certain technologies, the emergence of new technology, operating experience, prices and closure plans. The estimated timing of future decommissioning and restoration may change due to certain factors, including reserves life. Changes to estimates related to future expected costs, discount rates, inflation assumptions, and timing may have a material impact on the amounts presented.

Employee Future Benefits

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

Other Provisions

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

Income Taxes

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

Deferred Income Taxes

Deferred tax assets are recognized when it is considered probable that deductible temporary differences will be recovered in the foreseeable future. To the extent that future taxable income and the application of existing tax laws in each jurisdiction differ significantly from the company's estimate, the ability of the company to realize the deferred tax assets could be impacted.

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

Fair Value of Financial Instruments

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

Functional Currency

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

5. NEW IFRS STANDARDS

(a) Adoption of New IFRS Standards

IFRS 16 *Leases*

Effective January 1, 2019, the company adopted IFRS 16 *Leases* (IFRS 16) which replaces IAS 17 *Leases* (IAS 17) and requires the recognition of most leases on the balance sheet. IFRS 16 effectively removes the classification of leases as either finance or operating leases and treats all leases as finance leases for lessees with optional exemptions for short-term leases where the term is twelve months or less. The accounting treatment for lessors remains essentially unchanged, with the requirement to classify leases as either finance or operating.

The company has selected the modified retrospective transition approach, electing to adjust opening retained earnings with no restatement of comparative figures. As such, comparative information continues to be reported under IAS 17 and International Financial Reporting Interpretations Committee (IFRIC) 4. The details of accounting policies under IAS 17 and IFRIC 4 are disclosed separately if they are different from those under IFRS 16 and the impact of the change is disclosed below.

The company's accounting policy under IFRS 16 is as follows:

At inception of a contract, the company assesses whether a contract is, or contains, a lease based on whether the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration.

The company recognizes a right-of-use asset and a lease liability at the lease commencement date. The right-of-use asset is initially measured based on the initial amount of the lease liability adjusted for any lease payments made at or before the commencement date, plus any initial direct costs incurred and an estimate of costs to dismantle and remove the underlying asset or to restore the underlying asset or the site on which it is located, less any lease incentives received. The assets are depreciated to the earlier of the end of the useful life of the right-of-use asset or the lease term, where judgment is applied to determine the lease term of the lease contracts in which the company has a renewal option, using the straight-line method as this most closely reflects the expected pattern of consumption of the future economic benefits. In addition, the right-of-use assets may be periodically reduced by impairment losses, if any, and adjusted for certain remeasurements of the lease liability.

The lease liability is initially measured at the present value of the lease payments that are not paid at the commencement date, discounted using the interest rate implicit in the lease or, if that rate cannot be readily determined, the company's incremental borrowing rate. Lease payments include fixed payments, and variable payments that are based on an index or rate.

Cash payments for the principal portion of the lease liability are presented within the financing activities section and the interest portion of the lease liability is presented within the operating activities section of the statement of cash flows. Short-term lease payments and variable lease payments not included in the measurement of the lease liability are presented within the operating activities section of the statement of cash flows.

The lease liability is measured at amortized cost using the effective interest method. It is remeasured when there is a change in future lease payments arising from a change in an index or rate, if there is a change in the company's estimate of the amount expected to be payable under a residual value guarantee, or if the company changes its assessment of whether it will exercise a purchase, extension or termination option.

When the lease liability is remeasured in this way, a corresponding adjustment is made to the carrying amount of the right-of-use asset, or is recorded in profit or loss if the carrying amount of the right-of-use asset has been reduced to zero.

Under IAS 17

In the comparative period, the company classified leases that transferred substantially all of the risks and rewards of ownership as finance leases. When this was the case, the leased assets were measured initially at an amount equal to the lower of their fair value and the present value of minimum lease payments. Minimum lease payments were the payments over the lease term that the lessee was required to make, excluding any contingent rent.

Subsequently, the assets were accounted for in accordance with the accounting policy applicable to that asset.

Assets held under other leases were classified as operating leases and were not recognized in the company's statement of financial position. Payments made under operating leases were recognized in profit or loss on a straight-line basis over the term of the lease. Lease incentives received were recognized as an integral part of the total lease expense over the term of the lease.

As part of the initial application of IFRS 16, the company also chose to apply the following transitional provisions.

Right-of-use assets are measured at:

- An amount equal to the lease liability on January 1, 2019, adjusted by the amount of any prepaid or accrued lease payments relating to that lease recognized in the statement of financial position immediately before the date of transition.

The company applied the following practical expedients when applying IFRS 16 to leases previously classified as operating leases under IAS 17:

- Adjusted the right-of-use assets by the amount of any provision for onerous leases recognized in the balance sheet immediately before the date of initial application, as an alternative to performing an impairment review.
- Elected not to recognize right-of-use assets and lease liabilities for short-term leases that have a lease term of twelve months or less and leases with a short-term remaining life upon adoption. The lease payments associated with these leases are recognized as an expense on a straight-line basis over the lease term.
- Accounted for each lease component and any non-lease components as a single lease component for crude oil storage tanks.
- Used hindsight to determine the lease term if the contract contained options to extend or terminate the lease.

The following table summarizes the impact of adopting IFRS 16 on the company's Consolidated Balance Sheets at January 1, 2019. Prior period amounts have not been restated. The effects of the transition have been recognized through retained earnings in equity.

($ millions) Increase (Decrease)	December 31 2018	Adjustments due to IFRS 16	January 1 2019
Assets			
Current assets			
Accounts receivable	3 206	(2)	3 204
Property, plant and equipment, net	74 245	(1 267)	72 978
Right-of-use assets, net	—	3 059	3 059
Liabilities and Shareholders' Equity			
Current liabilities			
Current portion of long-term debt	229	(38)	191
Current portion of lease liabilities	—	276	276
Current portion of provisions	667	(1)	666
Long-term debt	13 890	(1 222)	12 668
Long-term lease liabilities	—	2 777	2 777
Other long-term liabilities	2 346	(1)	2 345
Provisions	6 984	(20)	6 964
Deferred income taxes	12 045	5	12 050
Equity	44 005	14	44 019

The following table reconciles the company's operating lease commitments as at December 31, 2018, as previously disclosed in the company's consolidated financial statements as at and for the year ended December 31, 2018, to the additional lease liabilities recognized on initial application of IFRS 16 as at January 1, 2019.

Reconciliation

($ millions)	January 1 2019
Operating leases as at December 31, 2018 (1)	2 457
Exemption for short-term leases	(42)
Discounting	(623)
Additional lease liabilities recognized due to adoption of IFRS 16 as at January 1, 2019	1 792

(1) Represents undiscounted lease commitments.

For leases that were previously classified as finance leases under IAS 17, within Property, Plant and Equipment, the carrying amount of the right-of-use asset and the lease liability recognized upon initial application as at January 1, 2019 was determined to be the carrying amount of the finance lease asset and liability under IAS 17 immediately before transition.

The lease liabilities recognized in accordance with IFRS 16 were discounted using the company's incremental borrowing rate upon initial application. The weighted average discount rate used for additional leases recognized as a result of application of IFRS 16 was 3.85% as at January 1, 2019.

Uncertainty over Income Tax Treatments

In June 2017, the IASB issued IFRIC 23 *Uncertainty over Income Tax Treatments*. The interpretation clarifies the accounting for current and deferred tax liabilities and assets in circumstances in which there is uncertainty over income tax treatments. The interpretation requires an entity to consider whether it is probable that a taxation authority will accept an uncertain tax treatment. If the entity considers it to be not probable that a taxation authority will accept an uncertain tax provision, the interpretation requires the entity to use the most likely amount or the expected value. The company adopted the amendment on its effective date of January 1, 2019. The adoption of this amendment did not have any impact on the company's consolidated financial statements.

(b) Recently Announced Accounting Pronouncements

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

Definition of a Business

In October 2018, the IASB issued *Definition of a Business (Amendments to IFRS 3).* The amendments narrowed and clarified the definition of a business. The amendments include an election to use a concentration test. This is a simplified assessment that results in an asset acquisition if substantially all of the fair value of the gross assets is concentrated in a single identifiable asset or a group of similar identifiable assets. If an election to use a concentration test is not made, or the test failed, then the assessment focuses on the existence of a substantive process. One important distinction is that "goodwill" can only be recognized as a result of acquiring a business, but not as a result of an asset acquisition. The amendments are effective for annual periods beginning on or after January 1, 2020 and are to be applied prospectively.

6. SEGMENTED INFORMATION

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

- Oil Sands includes the company's wholly owned operations in the Athabasca oil sands in Alberta to explore, develop and produce bitumen, synthetic crude oil and related products, through the recovery and upgrading of bitumen from mining and in situ operations. This segment also includes the company's joint interest in the Syncrude oil sands mining and upgrading operation, the company's joint interest in the Fort Hills partnership and the company's controlling interest in the East Tank Farm blending and storage facility located near Fort McMurray, Alberta as well as the marketing, supply, transportation and risk management of crude oil, natural gas, power and byproducts. The individual operating segments related to mining operations, in situ, Fort Hills and Syncrude have been aggregated into one reportable segment (Oil Sands) due to the similar nature of their business activities, including the production of bitumen, and the single geographic area and regulatory environment in which they operate.

- Exploration and Production (E&P) includes offshore activity in East Coast Canada, with interests in the Hibernia, Terra Nova, White Rose and Hebron oilfields, the exploration and production of crude oil and natural gas at Buzzard and Golden Eagle Area Development in the United Kingdom (U.K.), and exploration and production of crude oil at Oda and the development of the Fenja fields in Norway, as well as the marketing and risk management of crude oil and natural gas. Due to unrest in Syria, the company has declared force majeure under its contractual obligations, and Suncor's operations in Syria have been suspended indefinitely. Production in Libya remains partially shut-in due to political unrest, and the timing of a return to normal operations continues to be uncertain.

- Refining and Marketing includes the refining of crude oil products, and the distribution, marketing, transportation and risk management of refined and petrochemical products, and other purchased products through the retail and wholesale networks located in Canada and the United States (U.S.). The segment also includes trading of crude oil, natural gas and power.

The company also reports activities not directly attributable to an operating segment under Corporate and Eliminations. This includes renewable projects such as the wind power facilities of Chin Chute and Magrath in Alberta, SunBridge in Saskatchewan and Adelaide in Ontario as well as an investment in Enerkem Inc., a waste-to-biofuels and chemicals producer headquartered in Quebec.

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

For the years ended December 31[1][2] ($ millions)	Oil Sands 2019	Oil Sands 2018	Exploration and Production 2019	Exploration and Production 2018	Refining and Marketing 2019	Refining and Marketing 2018	Corporate and Eliminations 2019	Corporate and Eliminations 2018	Total 2019	Total 2018
Revenues and Other Income										
Gross revenues	**13 948**	12 039	**3 675**	3 869	**22 216**	23 655	**27**	29	**39 866**	39 592
Intersegment revenues	**4 399**	3 704	**—**	—	**88**	123	**(4 487)**	(3 827)	**—**	—
Less: Royalties	**(917)**	(398)	**(605)**	(652)	**—**	—	**—**	—	**(1 522)**	(1 050)
Operating revenues, net of royalties	**17 430**	15 345	**3 070**	3 217	**22 304**	23 778	**(4 460)**	(3 798)	**38 344**	38 542
Other income (loss)	**172**	387	**430**	(68)	**75**	68	**(32)**	57	**645**	444
	17 602	15 732	**3 500**	3 149	**22 379**	23 846	**(4 492)**	(3 741)	**38 989**	38 986
Expenses										
Purchases of crude oil and products	**1 407**	1 563	**—**	—	**15 296**	16 656	**(4 141)**	(4 086)	**12 562**	14 133
Operating, selling and general	**8 027**	7 577	**525**	507	**2 173**	2 043	**519**	446	**11 244**	10 573
Transportation	**1 293**	1 144	**80**	85	**120**	147	**(51)**	(57)	**1 442**	1 319
Depreciation, depletion, amortization and impairment	**8 170**	4 024	**1 505**	967	**823**	684	**74**	63	**10 572**	5 738
Exploration	**127**	44	**129**	78	**—**	—	**—**	—	**256**	122
(Gain) loss on asset exchange and disposal of assets	**(14)**	(108)	**(228)**	91	**(11)**	(7)	**—**	—	**(253)**	(24)
Financing expenses	**318**	320	**73**	46	**55**	7	**187**	1 769	**633**	2 142
	19 328	14 564	**2 084**	1 774	**18 456**	19 530	**(3 412)**	(1 865)	**36 456**	34 003
(Loss) earnings before Income Taxes	**(1 726)**	1 168	**1 416**	1 375	**3 923**	4 316	**(1 080)**	(1 876)	**2 533**	4 983
Income Tax (Recovery) Expense										
Current	**266**	(128)	**626**	680	**972**	1 090	**(312)**	(392)	**1 552**	1 250
Deferred	**(1 565)**	351	**(215)**	(112)	**(49)**	72	**(89)**	129	**(1 918)**	440
	(1 299)	223	**411**	568	**923**	1 162	**(401)**	(263)	**(366)**	1 690
Net (Loss) Earnings	**(427)**	945	**1 005**	807	**3 000**	3 154	**(679)**	(1 613)	**2 899**	3 293
Capital and Exploration Expenditures	**3 522**	3 546	**1 070**	946	**818**	856	**148**	58	**5 558**	5 406

(1) Beginning in 2019, results from the company's Energy Trading business are included within each of the respective operating business segments to which the respective trading activity relates. The Energy Trading business was previously reported within the Corporate, Energy Trading and Eliminations segment. Prior periods have been restated to reflect this change. The results from the company's Renewable Energy business continue to be included within the Corporate and Eliminations segment.

(2) The company adopted IFRS 16 on January 1, 2019 using the modified retrospective transition approach and, therefore, prior periods have not been restated. Refer to note 5 for further information.

Disaggregation of Revenue from Contracts with Customers and Intersegment Revenue

The company derives revenue from the transfer of goods mainly at a point in time in the following major commodities, revenue streams and geographical regions:

For the years ended December 31 [1] ($ millions)	2019 North America	2019 International	2019 Total	2018 North America	2018 International	2018 Total
Oil Sands						
SCO and diesel	**13 368**	**—**	**13 368**	11 659	—	11 659
Bitumen	**4 979**	**—**	**4 979**	4 084	—	4 084
	18 347	**—**	**18 347**	15 743	—	15 743
Exploration and Production						
Crude oil and natural gas liquids	**1 922**	**1 747**	**3 669**	1 741	2 112	3 853
Natural gas	**—**	**6**	**6**	3	13	16
	1 922	**1 753**	**3 675**	1 744	2 125	3 869
Refining and Marketing						
Gasoline	**9 941**	**—**	**9 941**	10 819	—	10 819
Distillate	**9 447**	**—**	**9 447**	9 698	—	9 698
Other	**2 916**	**—**	**2 916**	3 261	—	3 261
	22 304	**—**	**22 304**	23 778	—	23 778
Corporate and Eliminations	**(4 460)**	**—**	**(4 460)**	(3 798)	—	(3 798)
Total Gross Revenue from Contracts with Customers	**38 113**	**1 753**	**39 866**	37 467	2 125	39 592

(1) Beginning in 2019, results from the company's Energy Trading business are included within each of the respective operating business segments to which the respective trading activity relates. The Energy Trading business was previously reported within the Corporate, Energy Trading and Eliminations segment. Prior periods have been restated to reflect this change. The results from the company's Renewable Energy business continue to be included within the Corporate and Eliminations segment.

Geographical Information

Operating Revenues, net of Royalties

($ millions)	2019	2018
Canada	**31 157**	30 813
United States	**5 737**	5 999
Other foreign	**1 450**	1 730
	38 344	38 542

Non-Current Assets[1]

($ millions)	December 31 2019	December 31 2018
Canada	**75 190**	76 708
United States	**1 957**	1 889
Other foreign	**2 173**	2 154
	79 320	80 751

(1) Excludes deferred income tax assets.

7. OTHER INCOME

Other income consists of the following:

($ millions)	2019	2018
Risk management and trading activities [1]	**155**	255
(Losses) gains on valuation of inventory held for trading purposes	**(7)**	13
Investment and interest income	**89**	34
Insurance proceeds[2]	**431**	120
Other	**(23)**	22
	645	444

(1) Includes fair value changes related to derivative contracts in the Oil Sands, Exploration and Production, and Refining and Marketing segments.

(2) 2019 includes insurance proceeds for Libyan assets within the Exploration and Production segment (note 34). 2019 and 2018 include business interruption and property damage insurance proceeds for Syncrude within the Oil Sands segment.

8. OPERATING, SELLING AND GENERAL

Operating, Selling and General expense consists of the following:

($ millions)	2019	2018
Contract services[1]	**4 380**	4 552
Employee costs[1]	**3 641**	3 263
Materials	**869**	765
Energy	**1 129**	1 095
Equipment rentals and leases	**345**	360
Travel, marketing and other	**880**	538
	11 244	10 573

(1) The company incurred $8.5 billion of contract services and employee costs for the year ended December 31, 2019 (2018 – $8.3 billion), of which $8.0 billion (2018 – $7.8 billion) was recorded in Operating, Selling and General expense and $0.5 billion was recorded as Property, Plant and Equipment (2018 – $0.5 billion). Employee costs include salaries, benefits and share-based compensation.

9. FINANCING EXPENSES

Financing expenses consist of the following:

($ millions)	2019	2018
Interest on debt	**825**	897
Interest on lease liabilities[1]	**172**	—
Capitalized interest at 5.3% (2018 – 5.4%)	**(122)**	(156)
Interest expense	**875**	741
Interest on partnership liability	**55**	56
Interest on pension and other post-retirement benefits	**59**	56
Accretion	**270**	266
Foreign exchange (gain) loss on U.S. dollar denominated debt	**(624)**	1 090

Operational foreign exchange and other	**(2)**	(67)
	633	2 142

(1) The company adopted IFRS 16 on January 1, 2019 using the modified retrospective transition approach and, therefore, prior periods have not been restated. Refer to note 5 for further information.

10. INCOME TAXES

Income Tax (Recovery) Expense

($ millions)	2019	2018
Current:		
Current year	**1 524**	1 270
Adjustments to current income tax of prior years	**28**	(20)
Deferred:		
Origination and reversal of temporary differences	**(819)**	345
Adjustments in respect of deferred income tax of prior years	**83**	13
Changes in tax rates and legislation	**(1 124)**	—
Movement in unrecognized deferred income tax assets	**(58)**	82
Total income tax (recovery) expense	**(366)**	1 690

Reconciliation of Effective Tax Rate

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

($ millions)	2019	2018
Earnings before income tax	**2 533**	4 983
Canadian statutory tax rate	**26.74%**	27.04%
Statutory tax	**677**	1 347
Add (deduct) the tax effect of:		
Non-taxable component of capital (gains) losses	**(146)**	146
Share-based compensation and other permanent items	**25**	31
Assessments and adjustments	**112**	(7)
Impact of income tax rate and legislative changes	**(1 067)**	—
Foreign tax rate differential	**83**	111
Non-taxable component of acquisitions and dispositions	**—**	(14)
Movement in unrecognized deferred income tax assets	**(58)**	82
Other	**8**	(6)
Total income tax (recovery) expense	**(366)**	1 690
Effective tax rate	**(14.4)%**	33.9%

In the second quarter of 2019, Suncor recognized a deferred income tax recovery of $1.116 billion related to a decrease in the Alberta corporate tax rate from 12% to 8%. The tax rate decrease will be phased in as follows: 11% effective July 1, 2019, 10% effective January 1, 2020, 9% effective January 1, 2021, and 8% effective January 1, 2022. The deferred income tax recovery of $1.116 billion was comprised of $910 million recovery in the Oil Sands segment, $88 million recovery in the Refining and Marketing segment, $70 million recovery in the Exploration and Production segment, and $48 million recovery in the Corporate and Eliminations segment.

Deferred Income Tax Balances

The significant components of the company's deferred income tax (assets) liabilities and deferred income tax expense (recovery) are comprised of the following:

	Deferred Income Tax (Recovery) Expense		Deferred Income Tax Liability (Asset)	
($ millions)	**2019**	2018	**December 31 2019**	December 31 2018
Property, plant and equipment	**(2 348)**	484	**12 814**	14 666
Decommissioning and restoration provision	**259**	46	**(2 092)**	(1 854)
Employee retirement benefit plans	**32**	15	**(576)**	(585)
Tax loss carry-forwards	**16**	(63)	**(156)**	(172)
Other	**123**	(42)	**(23)**	(138)
Net deferred income tax (recovery) expense and liability	**(1 918)**	440	**9 967**	11 917

Change in Deferred Income Tax Balances

($ millions)	**2019**	2018
Net deferred income tax liability, beginning of year	**11 917**	11 433
Recognized in deferred income tax expense	**(1 918)**	440
Recognized in other comprehensive income	**(23)**	39
Foreign exchange, disposition and other	**(9)**	5
Net deferred income tax liability, end of year	**9 967**	11 917

Deferred Tax in Shareholders' Equity

($ millions)	**2019**	2018
Deferred Tax in Other Comprehensive Income		
Actuarial (loss) gain on employment retirement benefit plans	**(23)**	39
Total income tax (recovery) expense reported in equity	**(23)**	39

Deferred income tax assets are recognized for tax loss carry-forwards to the extent that the realization of the related tax benefit is probable based on estimated future earnings. Suncor has not recognized an $87 million (2018 – $153 million) deferred income tax asset on $715 million (2018 – $1,134 million) of capital losses related to foreign exchange on U.S. dollar denominated debt, which can only be utilized against future capital gains.

No deferred tax liability has been recognized at December 31, 2019, on temporary differences associated with earnings retained in our investments in foreign subsidiaries, as the company is able to control the timing of the reversal of these differences. Based on current plans, repatriation of funds in excess of foreign reinvestment will not result in material additional income tax expense. Deferred distribution taxes associated with international business operations have not been recorded.

11. EARNINGS PER COMMON SHARE

($ millions)	2019	2018
Net earnings	**2 899**	3 293
(millions of common shares)		
Weighted average number of common shares	**1 559**	1 623
Dilutive securities:		
Effect of share options	**2**	6
Weighted average number of diluted common shares	**1 561**	1 629
(dollars per common share)		
Basic earnings per share	**1.86**	2.03
Diluted earnings per share	**1.86**	2.02

12. CASH AND CASH EQUIVALENTS

($ millions)	December 31 2019	December 31 2018
Cash	**1 232**	1 285
Cash equivalents	**728**	936
	1 960	2 221

13. SUPPLEMENTAL CASH FLOW INFORMATION

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

($ millions)	2019	2018
Accounts receivable	**(1 099)**	219
Inventories	**(628)**	316
Accounts payable and accrued liabilities	**1 317**	(503)
Current portion of provisions	**(14)**	(110)
Income taxes payable (net)	**436**	511
	12	433
Relating to:		
Operating activities	**(397)**	408
Investing activities	**409**	25
	12	433

Reconciliation of movements of liabilities to cash flows arising from financing activities:

($ millions)	Short-Term Debt	Current Portion of Long-Term Lease Liabilities	Long-Term Lease Liabilities	Current Portion of Long-Term Debt	Long-Term Debt	Partnership Liability	Dividends Payable
At December 31, 2018	3 231	—	—	229	13 890	477	—
Changes from financing cash flows:							
Net repayment of commercial paper	(982)	—	—	—	—	—	—
Gross proceeds from issuance of long-term debt	—	—	—	—	750	—	—
Debt issuance costs	—	—	—	—	(5)	—	—
Repayment of long-term debt	—	—	—	(188)	—	—	—
Realized foreign exchange losses	—	—	—	7	—	—	—
Dividends paid on common shares	—	—	—	—	—	—	(2 614)
Payments of lease liabilities	—	(307)	—	—	—	—	—
Distributions to non-controlling interest	—	—	—	—	—	(7)	—
Non-cash changes:							
Dividends declared on common shares	—	—	—	—	—	—	2 614
Unrealized foreign exchange gains	(94)	—	—	(10)	(520)	—	—
Reclassification of debt to lease obligations	—	—	1 260	(38)	(1 222)	—	—
Reclassification of lease obligations	—	617	(617)	—	—	—	—
Deferred financing costs	—	—	—	—	(9)	—	—
Reassessment of partnership liability	—	—	—	—	—	(15)	—
New leases	—	—	1 978	—	—	—	—
At December 31, 2019	**2 155**	**310**	**2 621**	**—**	**12 884**	**455**	**—**

14. INVENTORIES

($ millions)	December 31 2019	December 31 2018
Crude oil[1]	**1 689**	1 424
Refined products	**1 290**	1 033
Materials, supplies and merchandise	**782**	702
	3 761	3 159

(1) Includes $210 million of inventories held for trading purposes (2018 – $247 million) which are measured at fair value less costs of disposal based on Level 1 and Level 2 fair value inputs.

During 2019, purchased product inventories of $13.3 billion (2018 – $14.8 billion) were recorded as an expense.

15. PROPERTY, PLANT AND EQUIPMENT

($ millions)	Oil and Gas Properties	Plant and Equipment	Total
Cost			
At December 31, 2017	36 209	78 639	114 848
Additions	1 221	3 958	5 179
Transfers from exploration and evaluation	31	—	31
Acquisitions (notes 32 to 34)	289	948	1 237
Changes in decommissioning and restoration	85	(22)	63
Disposals and derecognition	(375)	(4 785)	(5 160)
Foreign exchange adjustments	385	291	676
At December 31, 2018	37 845	79 029	116 874
Adoption of IFRS 16 (note 5)	**—**	**1 792**	**1 792**
Additions	**1 245**	**4 351**	**5 596**
Changes in decommissioning and restoration	**1 846**	**49**	**1 895**
Disposals and derecognition	**(116)**	**(439)**	**(555)**
Foreign exchange adjustments	**(224)**	**(214)**	**(438)**
At December 31, 2019	**40 596**	**84 568**	**125 164**
Accumulated provision			
At December 31, 2017	(17 975)	(23 380)	(41 355)
Depreciation, depletion, amortization and impairment	(1 739)	(3 849)	(5 588)
Disposals and derecognition	255	4 545	4 800
Foreign exchange adjustments	(324)	(162)	(486)
At December 31, 2018	(19 783)	(22 846)	(42 629)
Depreciation, depletion, amortization and impairment	**(2 871)**	**(7 764)**	**(10 635)**
Disposals and derecognition	**116**	**349**	**465**
Foreign exchange adjustments	**149**	**126**	**275**
At December 31, 2019	**(22 389)**	**(30 135)**	**(52 524)**
Net property, plant and equipment			
December 31, 2018	18 062	56 183	74 245
December 31, 2019	**18 207**	**54 433**	**72 640**

	December 31, 2019			December 31, 2018		
($ millions)	**Cost**	**Accumulated Provision**	**Net Book Value**	Cost	Accumulated Provision	Net Book Value
Oil Sands	**85 246**	**(30 581)**	**54 665**	80 295	(22 654)	57 641
Exploration and Production	**22 876**	**(15 298)**	**7 578**	21 867	(14 075)	7 792

Refining and Marketing	**15 342**	**(5 768)**	**9 574**	13 627	(5 092)	8 535
Corporate and Eliminations	**1 700**	**(877)**	**823**	1 085	(808)	277
	125 164	**(52 524)**	**72 640**	116 874	(42 629)	74 245

At December 31, 2019, the balance of assets under construction and not subject to depreciation or depletion was $5.6 billion (December 31, 2018 – $4.7 billion).

Due to continued volatility in the crude oil price environment and resulting declines in forecasted long-term heavy crude oil prices, the company performed an asset impairment test on its Fort Hills CGU in the Oil Sands segment. Due to an increase to forecasted capital expenditures within the White Rose CGU, the company also performed an impairment test within the Exploration and Production segment as at December 31, 2019. The impairment tests were performed using recoverable amounts based on the fair value less cost of disposal. An expected cash flow approach was used with the key assumptions discussed below (Level 3 fair value inputs – note 26):

Oil Sands

As a result of the impairment test, the company recorded impairment of $2.80 billion (net of taxes of $0.91 billion) on its share of the Fort Hills project in the Oil Sands segment using the following asset-specific assumptions:

- Western Canadian Select (WCS) price forecast of US$40.75/bbl in 2020, US$45.60/bbl in 2021, US$49.65/bbl in 2022, US$51.55/bbl in 2023 and US$52.90/bbl in 2024, escalating at 2% per year thereafter over the life of the project up to 2060, adjusted for asset-specific location and quality differentials;
- the company's share of production ranging from 96,000 to 106,000 bbls/d over the life of the project;
- cash operating costs averaging $22/bbl to $24/bbl over the life of the project (expressed in real dollars), reflects Operating, Selling and General expense adjusted for non-production costs including Share-based compensation, Research costs, and Excess power revenue; and
- risk-adjusted discount rate of 7.5% (after-tax).

The recoverable amount of the Fort Hills CGU was $7.7 billion as at December 31, 2019, which also includes the cost of carbon compliance in accordance with current provincial and federal regulations which starts at $30/tonne in 2020, reaches $50/tonne by 2022 and escalates at the rate of inflation thereafter. Estimate of the recoverable amount is most sensitive to the WCS price forecast and discount rate. A 5% decrease in price would have resulted in an increase to the impairment charge of approximately $1.2 billion (after-tax) on the company's share of the Fort Hills assets. A 1% increase in the discount rate would have resulted in an increase to the impairment charge of approximately $900 million (after-tax) on the company's share of the Fort Hills assets.

Exploration and Production

As a result of the impairment test, the company recorded impairment of $393 million (net of taxes of $128 million) on its share of the White Rose assets in the Exploration and Production segment using the following asset-specific assumptions:

- Brent price forecast of US$65/bbl in 2020, escalating at 2% per year thereafter over the life of the project up to 2036 and adjusted for asset-specific location and quality differentials;
- the company's share of production of approximately 8,700 bbls/d over the life of the project;
- the company's share of future capital expenditures of $1.4 billion, including the West White Rose expansion; and
- risk-adjusted discount rate of 9.0% (after-tax).

The recoverable amount of the White Rose CGU was $360 million as at December 31, 2019, which also includes the cost of carbon compliance in accordance with current provincial and federal regulations which starts at $30/tonne in 2020, reaches $50/tonne by 2022 and escalates at the rate of inflation thereafter. Estimate of the recoverable amount is most sensitive to the Brent price forecast and discount rate. A 5% decrease in price would have resulted in an increase to the impairment charge of approximately $85 million (after-tax) on the company's share of the White Rose assets. A 1% increase in the discount rate would have resulted in an increase to the impairment charge of approximately $35 million (after-tax) on the company's share of the White Rose assets.

16. RIGHT-OF-USE ASSETS AND LEASES

The company has lease contracts which include storage tanks, pipelines, railway cars, vessels, buildings, land, and mobile equipment for the purpose of production, storage and transportation of crude oil and related products.

Right-of-use (ROU) assets within Property, Plant and Equipment:

($ millions)	December 31 2019
Property, plant and equipment, net – excluding ROU assets	69 745
ROU assets	2 895
	72 640

The following table presents the ROU assets by asset class:

($ millions)	Plant and Equipment
Cost	
At January 1, 2019	3 326
Additions and adjustments	186
Foreign exchange	(7)
At December 31, 2019	**3 505**
Accumulated provision	
At January 1, 2019	(267)
Depreciation	(343)
At December 31, 2019	**(610)**
Net ROU assets	
At January 1, 2019 (note 5)	3 059
At December 31, 2019	**2 895**

Other lease-related items recognized in the Consolidated Statement of Comprehensive Income

($ millions)	For the year ended December 31, 2019
Operating, selling and general	
Short-term lease expense	236
Variable lease expense	45

There were no leases with residual value guarantees. Total cash outflow for leases was $464 million for the year ended December 31, 2019.

17. EXPLORATION AND EVALUATION ASSETS

($ millions)	December 31 2019	December 31 2018
Beginning of year	**2 319**	2 052
Acquisitions and additions (Note 32)	**193**	316
Transfers to oil and gas assets	**—**	(31)
Dry hole expenses	**(66)**	(11)
Disposals	**(16)**	(16)
Amortization	**—**	(1)
Foreign exchange adjustments	**(2)**	10
End of year	**2 428**	2 319

18. OTHER ASSETS

($ millions)	December 31 2019	December 31 2018
Investments	**289**	237
Prepaids and other	**905**	889
	1 194	1 126

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

19. GOODWILL AND OTHER INTANGIBLE ASSETS

	Oil Sands	Refining and Marketing			
($ millions)	Goodwill	Goodwill	Brand Name	Customer Lists	Total
At December 31, 2017	2 752	140	162	7	3 061
Additions	—	—	—	4	4
Amortization	—	—	—	(4)	(4)
At December 31, 2018	2 752	140	162	7	3 061
Amortization	**—**	**—**	**—**	**(3)**	**(3)**
At December 31, 2019	**2 752**	**140**	**162**	**4**	**3 058**

The company performed a goodwill impairment test at December 31, 2019 on its Oil Sands segment. Recoverable amounts were based on fair value less costs of disposal calculated using the present value of the segments' expected future cash flows.

Cash flow forecasts are based on past experience, historical trends and third-party evaluations of the company's reserves and resources to determine production profiles and volumes, operating costs, maintenance and capital expenditures. Production profiles, reserves volumes, operating costs, maintenance and capital expenditures are validated against the estimates approved through the company's annual reserves evaluation process and determine the duration of the underlying cash flows used in the discounted cash flow test. Projected cash flows reflect current market assessments of key assumptions, including long-term forecasts of commodity prices, inflation rates, foreign exchange rates and discount rates specific to the asset (Level 3 fair value inputs).

Future cash flow estimates are discounted using after-tax risk-adjusted discount rates. The discount rates are calculated based on the weighted average cost of capital of a group of relevant peers that is considered to represent the rate of return that

would be required by a typical market participant for similar assets. The after-tax discount rate applied to cash flow projections was 7.5% (2018 – 8%). The company based its cash flow projections on a West Texas Intermediate price of US$60/bbl in 2020 and escalating at an average of 2% thereafter, adjusted for applicable quality and location differentials depending on the underlying CGU. The forecast cash flow period ranged from 20 years to 45 years based on the reserves life of the respective CGU. As a result of this analysis, an impairment of $2.80 billion (net of taxes of $0.91 billion) on company's share of the Fort Hills CGU was recorded (note 15); however, management did not identify any impairment of goodwill within any of the CGUs comprising the Oil Sands operating segment.

The company also performed a goodwill impairment test of its Refining and Marketing CGUs. The recoverable amounts are based on fair value less costs of disposal calculated using the present value of the CGUs' expected future cash flows, based primarily on historical results adjusted for current economic conditions.

20. DEBT AND CREDIT FACILITIES

Debt and credit facilities are comprised of the following:

Short-Term Debt

($ millions)	**December 31 2019**	December 31 2018
Commercial paper[1]	**2 155**	3 231

(1) The commercial paper is supported by a revolving credit facility with a syndicate of lenders. The company is authorized to issue commercial paper to a maximum of $5.0 billion having a term not to exceed 365 days. The weighted average interest rate as at December 31, 2019 was 2.05% (December 31, 2018 – 2.88%).

Long-Term Debt

($ millions)	December 31 2019	December 31 2018
Fixed-term debt[2][3]		
7.75% Notes, due 2019 (US$140) [4]	**—**	191
3.10% Series 5 Medium Term Notes, due 2021	**749**	749
9.25% Debentures, due 2021 (US$300)	**403**	431
9.40% Notes, due 2021 (US$220) [4][5]	**292**	315
4.50% Notes, due 2022 (US$182) [4]	**225**	234
3.60% Notes, due 2024 (US$750)	**968**	1 020
3.00% Series 5 Medium Term Notes, due 2026	**698**	698
7.875% Debentures, due 2026 (US$275)	**372**	393
8.20% Notes, due 2027 (US$59) [4]	**82**	87
7.00% Debentures, due 2028 (US$250)	**329**	346
3.10% Series 6 Medium Term Notes, due 2029	**750**	—
7.15% Notes, due 2032 (US$500)	**647**	681
5.35% Notes, due 2033 (US$300)	**361**	379
5.95% Notes, due 2034 (US$500)	**646**	680
5.95% Notes, due 2035 (US$600)	**747**	786
5.39% Series 4 Medium Term Notes, due 2037	**599**	599
6.50% Notes, due 2038 (US$1 150)	**1 487**	1 565
6.80% Notes, due 2038 (US$900)	**1 186**	1 249
6.85% Notes, due 2039 (US$750)	**969**	1 021
6.00% Notes, due 2042 (US$152) [4]	**150**	158
4.34% Series 5 Medium Term Notes, due 2046	**300**	300
4.00% Notes, due 2047 (US$750)	**967**	1 018
Total unsecured long-term debt	**12 927**	12 900
Finance leases[6][7]	**—**	1 260
Lease liabilities[8] (note 5)	**2 931**	—
Deferred financing costs	**(43)**	(41)
	15 815	14 119
Current portion of long-term debt and lease liabilities		
Finance leases[6]	**—**	(38)
Lease liabilities (note 5)	**(310)**	—
Long-term debt	**—**	(191)

	(310)	(229)
Total long-term lease liabilities	**2 621**	—
Total long-term debt	**12 884**	13 890

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

(3) Certain securities are redeemable at the option of the company.

(4) Debt acquired through the acquisition of Canadian Oil Sands Limited (COS).

(5) Subsequent to the acquisition of COS, Moody's Investors Service downgraded COS long-term senior debt rating from Baa3 (negative outlook) to Ba3 (stable outlook). This triggered a change in the coupon rate of the note from 7.9% to 9.4%.

(6) The company adopted IFRS 16 on January 1, 2019 using the modified retrospective transition approach and, therefore, prior periods have not been restated. Refer to note 5 for further information.

(7) Interest rates range from 2.9% to 16.5% and maturity dates range from 2027 to 2062.

(8) Interest rates range from 2.0% to 14.2% and maturity dates range from 2020 to 2062.

In 2019, the company re-paid its US$140 million (book value of $188 million) senior unsecured notes at maturity, with a coupon of 7.75%, for US$145 million ($195 million), including US$5 million ($7 million) of accrued interest.

In 2019, the company issued $750 million of senior unsecured Series 6 Medium Term Notes maturing on May 24, 2029. The Series 6 Medium Term Notes have a coupon of 3.10% and were priced at $99.761 per $100 principal amount for an effective yield of 3.128%. Interest is paid semi-annually.

In 2018, the company completed an early retirement of US$83 million (book value of $109 million) of subsidiary debt acquired through the acquisition of COS with a coupon of 7.75% originally scheduled to mature on May 15, 2019 for US$88 million ($116 million). The early retirement payment included US$3 million ($4 million) of accrued interest, resulting in a debt extinguishment loss of $3 million ($2 million after-tax).

Scheduled Debt Repayments

Scheduled principal repayments as at December 31, 2019 for lease liabilities, short-term debt and long-term debt are as follows:

($ millions)	Repayment
2020	2 457
2021	1 699
2022	451
2023	175
2024	1 139
Thereafter	12 132
	18 053

Credit Facilities

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

($ millions)	2019
Fully revolving and expires in 2023	**3 500**
Fully revolving and expires in 2022	**3 241**
Fully revolving and expires in 2021	**1 455**
Can be terminated at any time at the option of the lenders	**132**
Total credit facilities	**8 328**
Credit facilities supporting outstanding commercial paper	**(2 155)**
Credit facilities supporting standby letters of credit [(1)]	**(1 284)**
Total unutilized credit facilities [(2)]	**4 889**

(1) To reduce costs, the company supported certain credit facilities with $206 million cash collateral as at December 31, 2019 (December 31, 2018 – $108 million).

(2) Available credit facilities for liquidity purposes at December 31, 2019 increased to $4.701 billion, compared to $3.608 billion at December 31, 2018.

21. OTHER LONG-TERM LIABILITIES

($ millions)	**December 31 2019**	December 31 2018
Pensions and other post-retirement benefits (note 22)	**1 577**	1 420
Share-based compensation plans (note 25)	**289**	259
Partnership liability[1]	**446**	470
Deferred revenue	**40**	46
Libya Exploration and Production Sharing Agreement (EPSA) signature bonus [2]	**79**	83
Other	**68**	68
	2 499	2 346

(1) The company paid $62 million in 2019 (2018 – $62 million) in distributions to the partners, of which $55 million (2018 – $56 million) was allocated to interest expense and $7 million (2018 – $6 million) to the principal.

(2) As part of the 2009 acquisition of Petro-Canada, the company assumed the remaining US$500 million obligation for a signature bonus relating to Petro-Canada's ratification of six EPSAs in Libya. At December 31, 2019, the carrying amount of the Libya EPSAs' signature bonus was $81 million (December 31, 2018 – $85 million). The current portion is $2 million (December 31, 2018 – $2 million) and is recorded in Accounts Payable and Accrued Liabilities.

22. PENSIONS AND OTHER POST-RETIREMENT BENEFITS

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

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

Funding of the registered retirement plans complies with applicable regulations that require actuarial valuations of the pension funds at least once every three years in Canada and the U.K., and every year in the United States and Germany. The most recent valuations for the registered Canadian plans and U.K. were performed as at December 31, 2019. The company uses a measurement date of December 31 to value the plan assets and remeasure the accrued benefit obligation for accounting purposes.

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

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

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

Defined Benefit Obligations and Funded Status

($ millions)	Pension Benefits 2019	Pension Benefits 2018	Other Post-Retirement Benefits 2019	Other Post-Retirement Benefits 2018
Change in benefit obligation				
Benefit obligation at beginning of year	**6 730**	6 717	**557**	597
Obligations acquired through acquisition (note 32)	**—**	185	**—**	8
Current service costs	**220**	235	**13**	13
Plan participants' contributions	**16**	15	**—**	—
Benefits paid	**(293)**	(296)	**(24)**	(23)
Interest costs	**255**	236	**22**	21
Foreign exchange	**(13)**	14	**(1)**	1
Settlements	**5**	5	**—**	—
Actuarial remeasurement:				
Experience gain arising on plan liabilities	**(11)**	(26)	**(2)**	(18)
Actuarial gain arising from changes in demographic assumptions	**—**	(1)	**—**	—
Actuarial loss (gain) arising from changes in financial assumptions	**799**	(354)	**66**	(42)
Benefit obligation at end of year	**7 708**	6 730	**631**	557
Change in plan assets				
Fair value of plan assets at beginning of year	**5 795**	5 799	**—**	—
Assets acquired through acquisition (note 32)	**—**	153	**—**	—
Employer contributions	**157**	182	**—**	—
Plan participants' contributions	**16**	15	**—**	—
Benefits paid	**(269)**	(273)	**—**	—
Foreign exchange	**(8)**	14	**—**	—
Settlements	**5**	5	**—**	—
Administrative costs	**(2)**	(2)	**—**	—
Income on plan assets	**218**	201	**—**	—
Actuarial remeasurement:				
Return on plan assets greater than (less than) discount rate	**781**	(299)	**—**	—
Fair value of plan assets at end of year	**6 693**	5 795	**—**	—
Net unfunded obligation	**1 015**	935	**631**	557

Of the total net unfunded obligations as at December 31, 2019, 97% relates to Canadian pension plans and other post-retirement benefits obligation (December 31, 2018 – 98%). The weighted average duration of the defined benefit obligation under the Canadian pension plans and other post-retirement plans is 14.60 years (2018 – 14.75 years).

The net unfunded obligation is recorded in Accounts Payable and Accrued Liabilities and Other Long-Term Liabilities (note 21) in the Consolidated Balance Sheets.

($ millions)	Pension Benefits 2019	Pension Benefits 2018	Other Post-Retirement Benefits 2019	Other Post-Retirement Benefits 2018
Analysis of amount charged to earnings:				
Current service costs	**220**	235	**13**	13
Interest costs	**37**	35	**22**	21
Defined benefit plans expense	**257**	270	**35**	34
Defined contribution plans expense	**82**	77	**—**	—
Total benefit plans expense charged to earnings	**339**	347	**35**	34

Components of defined benefit costs recognized in Other Comprehensive Income:

($ millions)	Pension Benefits 2019	Pension Benefits 2018	Other Post-Retirement Benefits 2019	Other Post-Retirement Benefits 2018
Return on plan assets (excluding amounts included in net interest expense)	**(781)**	299	**—**	—
Experience gain arising on plan liabilities	**(11)**	(26)	**(2)**	(18)
Actuarial loss (gain) arising from changes in financial assumptions	**799**	(354)	**66**	(42)
Actuarial gain arising from changes in demographic assumptions	**—**	(1)	**—**	—
Actuarial loss (gain) recognized in other comprehensive income	**7**	(82)	**64**	(60)

Actuarial Assumptions

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

The significant weighted average actuarial assumptions were as follows:

(%)	Pension Benefits December 31 2019	Pension Benefits December 31 2018	Other Post-Retirement Benefits December 31 2019	Other Post-Retirement Benefits December 31 2018
Discount rate	**3.10**	3.80	**3.10**	3.90
Rate of compensation increase	**3.00**	3.00	**3.00**	3.00

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

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

In order to measure the expected cost of other post-retirement benefits, it was assumed for 2019 that the health care costs would increase annually by 6.50% per person (2018 – 6.50%). From 2020, this rate will decrease 0.5% annually to 5% by 2022, and remain at that level thereafter.

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

($ millions)	Pension Benefits Increase	Pension Benefits Decrease
1% change in discount rate		
Effect on the aggregate service and interest costs	(25)	31
Effect on the benefit obligations	(988)	1 271

($ millions)	Other Post-Retirement Benefits Increase	Other Post-Retirement Benefits Decrease
1% change in discount rate		
Effect on the benefit obligations	(74)	91
1% change in health care cost		
Effect on the aggregate service and interest costs	1	(1)
Effect on the benefit obligations	30	(26)

Plan Assets and Investment Objectives

The company's long-term investment objective is to secure the defined pension benefits while managing the variability and level of its contributions. The portfolio is rebalanced periodically, as required, to the plans' target asset allocation as prescribed in the Statement of Investment Policies and Procedures approved by the Board of Directors. Plan assets are restricted to those permitted by legislation, where applicable. Investments are made through pooled, mutual, segregated or exchange traded funds.

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

(%)	**2019**	2018
Equities, comprised of:		
– Canada	**12**	13
– United States	**19**	17
– Foreign	**19**	18
	50	48
Fixed income, comprised of:		
– Canada	**41**	43
Real estate, comprised of:		
– Canada	**9**	9
Total	**100**	100

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

During the year, the company made cash contributions of $157 million (2018 – $182 million) to its defined benefit pension plans, of which $2 million (2018 – $2 million) was contributed to the solvency reserve account in Alberta. The company expects to make cash contributions to its defined benefit pension plans in 2020 of $176 million.

23. PROVISIONS

($ millions)	Decommissioning and Restoration[1]	Royalties	Other[2]	Total
At December 31, 2017	7 465	240	254	7 959
Liabilities incurred	345	9	101	455
Change in discount rate	(663)	—	—	(663)
Changes in estimates	114	(67)	(16)	31
Liabilities settled	(469)	(84)	(25)	(578)
Accretion	266	—	—	266
Asset acquisitions	133	—	—	133
Foreign exchange	48	—	—	48
At December 31, 2018	7 239	98	314	7 651
Less: current portion	(538)	(98)	(31)	(667)
	6 701	—	283	6 984
At December 31, 2018	7 239	98	314	7 651
Adoption of IFRS 16 impact (note 5)	**—**	**—**	**(21)**	**(21)**
At January 1, 2019, adjusted	**7 239**	**98**	**293**	**7 630**
Liabilities incurred	**346**	**60**	**(4)**	**402**
Change in discount rate	**1 344**	**—**	**—**	**1 344**
Changes in estimates	**193**	**(25)**	**1**	**169**
Liabilities settled	**(464)**	**—**	**(14)**	**(478)**
Accretion	**270**	**—**	**—**	**270**
Asset disposals	**(1)**	**—**	**—**	**(1)**
Foreign exchange	**(29)**	**—**	**—**	**(29)**
At December 31, 2019	**8 898**	**133**	**276**	**9 307**
Less: current portion	**(475)**	**(133)**	**(23)**	**(631)**
	8 423	**—**	**253**	**8 676**

(1) Represents decommissioning and restoration provisions associated with the retirement of Property, Plant and Equipment and Exploration and Evaluation assets. The total undiscounted amount of estimated future cash flows required to settle the obligations at December 31, 2019 was approximately $12.9 billion (December 31, 2018 – $13.0 billion). A weighted average credit-adjusted risk-free interest rate of 3.30% was used to discount the provision recognized at December 31, 2019 (December 31, 2018 – 4.20%). The credit-adjusted risk-free interest rate used reflects the expected time frame of the provisions. Payments to settle the decommissioning and restoration provisions occur on an ongoing basis and will continue over the lives of the operating assets, which can exceed 50 years.

(2) Includes legal and environmental provisions.

Sensitivities

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

As at December 31	**2019**	2018
1% Increase	**(1 629)**	(1 099)
1% Decrease	**2 365**	1 521

24. SHARE CAPITAL

Authorized

Common Shares

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

Preferred Shares

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

Normal Course Issuer Bid

On May 1, 2018, the company announced its intent to continue its normal course issuer bid program (the 2018 NCIB) to repurchase common shares through the facilities of the Toronto Stock Exchange (the TSX), New York Stock Exchange (the NYSE) and/or alternative trading platforms. Pursuant to the 2018 NCIB, the company was permitted to purchase for cancellation up to 52,285,330 of its common shares between May 4, 2018 and May 3, 2019. On November 14, 2018, Suncor announced an amendment to the 2018 NCIB, effective as of November 19, 2018, which increased the maximum number of aggregate common shares that it was permitted to repurchase for cancellation between May 4, 2018 and May 3, 2019 to 81,695,830.

On May 1, 2019, the company announced its intention to renew its existing normal course issuer bid program (the 2019 NCIB) to continue to repurchase shares under its previously announced buyback program through the facilities of the TSX, NYSE and/or alternative trading platforms. Pursuant to the 2019 NCIB, the company is permitted to purchase for cancellation up to 50,252,231 of its common shares between May 6, 2019 and May 5, 2020. On December 23, 2019, Suncor announced an amendment to the 2019 NCIB, effective as of December 30, 2019, which allows the company to increase the maximum number of aggregate common shares that may be repurchased between May 6, 2019 and May 5, 2020 to 78,549,178. Subsequent to the year end, the Board of Directors approved a further share repurchase program of up to $2.0 billion beginning on March 1, 2020.

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

($ millions except as noted)	**2019**	2018
Share repurchase activities (thousands of common shares)		
Shares repurchased	**55 298**	64 426
Amounts charged to		
Share capital	**905**	1 040
Retained earnings	**1 369**	2 013
Share repurchase cost	**2 274**	3 053
Average repurchase cost per share (dollars)	**41.12**	47.38

Under an automatic repurchase plan agreement with an independent broker, the company has recorded the following liability for share repurchases that may take place during its internal blackout period:

($ millions)	**December 31 2019**	December 31 2018
Amounts charged to		
Share capital	**65**	111
Retained earnings	**103**	152
Liability for share purchase commitment	**168**	263

25. SHARE-BASED COMPENSATION

Share-Based Compensation Expense

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

($ millions)	2019	2018
Equity-settled plans	**50**	46
Cash-settled plans	**274**	181
Total share-based compensation expense	**324**	227

Liability Recognized for Share-Based Compensation

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

($ millions)	2019	2018
Current liability	**242**	286
Long-term liability (note 21)	**289**	259
Total Liability	**531**	545

The intrinsic value of the vested awards at December 31, 2019 was $300 million (December 31, 2018 – $328 million).

Stock Option Plans

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

(a) Active Stock Option Plan

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

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

	2019	2018
Annual dividend per share (dollars)	**1.68**	1.44
Risk-free interest rate	**1.78%**	2.03%
Expected life	**5 years**	5 years
Expected volatility	**26%**	24%
Weighted average fair value per option (dollars)	**6.61**	6.73

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

(b) Discontinued Stock Option Plans

Executive and Key Contributor Stock Options

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

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

	2019		2018	
	Number (thousands)	**Weighted Average Exercise Price ($)**	Number (thousands)	Weighted Average Exercise Price ($)
Outstanding, beginning of year	**28 935**	**38.25**	31 110	36.96
Granted	**7 756**	**42.96**	7 231	43.19
Exercised as options for common shares	**(2 688)**	**33.37**	(7 927)	35.95
Forfeited/expired	**(121)**	**42.57**	(1 479)	47.88
Outstanding, end of year	**33 882**	**39.70**	28 935	38.25
Exercisable, end of year	**21 535**	**37.86**	15 374	36.10

Options are exercised regularly throughout the year. Therefore, the weighted average share price during the year of $40.82 (2018 – $46.99) is representative of the weighted average share price at the date of exercise.

For the options outstanding at December 31, 2019, the exercise price ranges and weighted average remaining contractual lives are shown below:

	Outstanding			Exercisable	
Exercise Prices ($)	Number (thousands)	Weighted Average Remaining Contractual Life (years)	Weighted Average Exercise Price ($)	Number (thousands)	Weighted Average Exercise Price ($)
30.21-34.99	**5 614**	3	30.36	**5 614**	30.36
35.00-39.99	**6 851**	2	37.74	**6 782**	37.74
40.00-44.99	**21 235**	5	42.70	**9 078**	42.50
45.00-49.99	**54**	6	48.00	**18**	48.04
50.00-54.27	**128**	6	52.40	**43**	52.40
Total	**33 882**	4	39.70	**21 535**	37.86

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

(thousands)	2019	2018
	14 295	21 929

Share Unit Plans

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

(a) Performance Share Units (PSUs)

A PSU is a time-vested award entitling employees to receive varying degrees of cash (0% – 200% of the company's share price at time of vesting) contingent upon Suncor's total shareholder return (stock price appreciation and dividend income) relative to a peer group of companies. Cash payments for awards granted in 2019 and onwards are contingent upon Suncor's total shareholder return and annual return on capital employed performance. PSUs vest approximately three years after the grant date.

(b) Restricted Share Units (RSUs)

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

(c) Deferred Share Units (DSUs)

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

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

(thousands)	PSU	RSU	DSU
Outstanding, December 31, 2017	2 267	16 072	1 302
Granted	1 553	4 796	192
Redeemed for cash	(1 623)	(5 962)	(189)
Forfeited/expired	—	(314)	—
Outstanding, December 31, 2018	2 197	14 592	1 305
Granted	**1 212**	**4 861**	**200**
Redeemed for cash	**(1 210)**	**(5 577)**	**(217)**
Forfeited/expired	**(6)**	**(274)**	**(1)**
Outstanding, December 31, 2019	**2 193**	**13 602**	**1 287**

Stock Appreciation Rights (SARs)

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

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

The following table presents a summary of the activity related to Suncor's SARs plan:

	2019		2018	
	Number (thousands)	**Weighted Average Exercise Price ($)**	Number (thousands)	Weighted Average Exercise Price ($)
Outstanding, beginning of year	**363**	**38.60**	387	36.38
Granted	**112**	**42.95**	108	43.09
Exercised	**(44)**	**34.53**	(126)	35.65
Forfeited/expired	**(46)**	**42.85**	(6)	38.36
Outstanding, end of year	**385**	**39.83**	363	38.60
Exercisable, end of year	**223**	**37.62**	170	36.57

26. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

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

Non-Derivative Financial Instruments

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

The company's long-term debt and long-term financial liabilities are recorded at amortized cost using the effective interest method. At December 31, 2019, the carrying value of fixed-term debt accounted for under amortized cost was $12.9 billion (December 31, 2018 – $12.9 billion) and the fair value at December 31, 2019 was $16.1 billion (December 31, 2018 – $14.2 billion). The increase in fair value of debt is mainly due to the decline in interest rates during the year. The estimated fair value of long-term debt is based on pricing sourced from market data, which is considered a Level 2 fair value input.

Suncor entered into a partnership with Fort McKay First Nation (FMFN) and Mikisew Cree First Nation (MCFN) in 2018 where FMFN and MCFN acquired a combined 49% partnership interest in the East Tank Farm Development. The partnership liability is recorded at amortized cost using the effective interest method. At December 31, 2019, the carrying value of the Partnership liability accounted for under amortized cost was $455 million (December 31, 2018 – $477 million).

Derivative Financial Instruments

(a) Non-Designated Derivative Financial Instruments

The company uses derivative financial instruments, such as physical and financial contracts, to manage certain exposures to fluctuations in interest rates, commodity prices and foreign currency exchange rates, as part of its overall risk management program, as well as for trading purposes.

The changes in the fair value of non-designated derivatives are as follows:

($ millions)	2019	2018
Fair value outstanding, beginning of year	**60**	(105)
Cash Settlements – received during the year	**(254)**	(90)
Changes in fair value recognized in earnings during the year (note 7)	**155**	255
Fair value outstanding, end of year	**(39)**	60

(b) Fair Value Hierarchy

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

- Level 1 consists of instruments with a fair value determined by an unadjusted quoted price in an active market for identical assets or liabilities. An active market is characterized by readily and regularly available quoted prices where the prices are representative of actual and regularly occurring market transactions to assure liquidity.
- Level 2 consists of instruments with a fair value that is determined by quoted prices in an inactive market, prices with observable inputs, or prices with insignificant non-observable inputs. The fair value of these positions is determined using observable inputs from exchanges, pricing services, third-party independent broker quotes, and published transportation tolls. The observable inputs may be adjusted using certain methods, which include extrapolation over the quoted price term and quotes for comparable assets and liabilities.
- Level 3 consists of instruments with a fair value that is determined by prices with significant unobservable inputs. As at December 31, 2019, the company does not have any derivative instruments measured at fair value Level 3.

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

The following table presents the company's derivative financial instrument assets and liabilities and assets available for sale measured at fair value for each hierarchy level as at December 31, 2019 and 2018.

($ millions)	Level 1	Level 2	Level 3	Total Fair Value
Accounts receivable	63	152	—	215
Accounts payable	(43)	(112)	—	(155)
Balance at December 31, 2018	20	40	—	60
Accounts receivable	**33**	**61**	**—**	**94**
Accounts payable	**(66)**	**(67)**	**—**	**(133)**
Balance at December 31, 2019	**(33)**	**(6)**	**—**	**(39)**

During the year ended December 31, 2019, there were no transfers between Level 1 and Level 2 fair value measurements.

Offsetting Financial Assets and Liabilities

The company enters into arrangements that allow for offsetting of derivative financial instruments and accounts receivable (payable), which are presented on a net basis on the balance sheet, as shown in the table below as at December 31, 2019 and 2018.

Financial Assets

($ millions)	Gross Assets	Gross Liabilities Offset	Net Amounts Presented
Fair value of derivative assets	1 599	(1 384)	215
Accounts receivable	1 837	(882)	955
Balance at December 31, 2018	3 436	(2 266)	1 170
Fair value of derivative assets	**1 737**	**(1 643)**	**94**
Accounts receivable	**2 860**	**(1 289)**	**1 571**
Balance at December 31, 2019	**4 597**	**(2 932)**	**1 665**

Financial Liabilities

($ millions)	Gross Liabilities	Gross Assets Offset	Net Amounts Presented
Fair value of derivative liabilities	(1 539)	1 384	(155)
Accounts payable	(1 798)	882	(916)
Balance at December 31, 2018	(3 337)	2 266	(1 071)
Fair value of derivative liabilities	**(1 776)**	**1 643**	**(133)**
Accounts payable	**(2 532)**	**1 289**	**(1 243)**
Balance at December 31, 2019	**(4 308)**	**2 932**	**(1 376)**

Risk Management

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

The company maintains a formal governance process to manage its financial risks. The company's Commodity Risk Management Committee (CRMC) is charged with the oversight of the company's trading and credit risk management activities. These activities are intended to manage

risk associated with open price exposure of specific volumes in transit or storage, enhance the company's operations, and enhance profitability through informed market calls, market diversification, economies of scale, improved transportation access, and leverage of assets, both physical and contractual. The CRMC, acting

under the authority of the company's Board of Directors, meets regularly to monitor limits on risk exposures, review policy compliance and validate risk-related methodologies and procedures.

The nature of the risks faced by the company and its policies for managing such risks remain unchanged from December 31, 2018.

1) Market Risk

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

(a) Commodity Price Risk

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

An increase of US$10/bbl of crude oil as at December 31, 2019 would decrease pre-tax earnings for the company's outstanding derivative financial instruments by approximately $46 million (2018 – $39 million).

(b) Foreign Currency Exchange Risk

The company is exposed to foreign currency exchange risk on revenues, capital expenditures, or financial instruments that are denominated in a currency other than the company's functional currency (Canadian dollars). As crude oil is priced in U.S. dollars, fluctuations in US$/Cdn$ exchange rates may have a significant impact on revenues. This exposure is partially offset through the issuance of U.S. dollar denominated debt. A 1% strengthening in the Cdn$ relative to the US$ as at December 31, 2019 would increase pre-tax earnings related to the company's debt by approximately $146 million (2018 – $167 million).

(c) Interest Rate Risk

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

To manage the company's exposure to interest rate volatility, the company may periodically enter into interest rate swap contracts to fix the interest rate of future debt issuances. As at December 31, 2019, the company had no outstanding forward starting swaps. The weighted average interest rate on total debt, including lease liabilities, for the year ended December 31, 2019 was 5.6% (2018 – 5.4%).

The company's net earnings are sensitive to changes in interest rates on the floating rate portion of the company's debt, which are offset by cash balances. To the extent interest expense is not capitalized, if interest rates applicable to floating rate instruments increased by 1%, it is estimated that the company's pre-tax earnings would decrease by approximately $2 million (2018 – approximately $10 million). This assumes that the amount and mix of fixed and floating rate debt remains unchanged from December 31, 2019. The proportion of floating interest rate exposure at December 31, 2019 was 12.0% of total debt outstanding (2018 – 18.6%).

2) Liquidity Risk

Liquidity risk is the risk that Suncor will not be able to meet its financial obligations when due. The company mitigates this risk by forecasting spending requirements as well as cash flow from operating activities, and maintaining sufficient cash, credit facilities, and debt shelf prospectuses to meet these requirements. Suncor's cash and cash equivalents and total credit facilities at December 31, 2019 were $2.0 billion and $8.3 billion, respectively. Of Suncor's $8.3 billion in total credit facilities, $4.9 billion were available at December 31, 2019. In addition, Suncor has $2.25 billion of unused capacity under a Canadian debt shelf prospectus and an unused capacity of US$3.0 billion under a U.S. debt shelf prospectus. The ability of the company to raise additional capital utilizing these shelf prospectuses is dependent on market conditions. The company believes it has sufficient funding through the use of these facilities and access to capital markets to meet its future capital requirements.

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

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

	December 31, 2018		
($ millions)	Trade and Other Payables[1]	Gross Derivative Liabilities[2]	Debt[3]
Within one year	5 492	1 539	4 314
1 to 3 years	42	—	3 362
3 to 3 years	42	—	1 827
Over 5 years	—	—	20 611
	5 576	1 539	30 114

	December 31, 2019			
($ millions)	**Trade and Other Payables[1]**	**Gross Derivative Liabilities[2]**	**Debt[3]**	**Lease Liabilities[4]**
Within one year	**6 422**	**1 568**	**2 877**	**470**
1 to 3 years	**39**	**208**	**2 991**	**796**
3 to 5 years	**40**	**—**	**2 220**	**616**
Over 5 years	**—**	**—**	**17 183**	**2 960**
	6 501	**1 776**	**25 271**	**4 842**

(1) Trade and other payables exclude net derivative liabilities of $133 million (2018 – $155 million).

(2) Gross derivative liabilities of $1 776 million (2018 – $1 539 million) are offset by gross derivative assets of $1 643 million (2018 – $1 384 million), resulting in a net amount of $133 million (2018 – $155 million).

(3) 2018 debt includes short-term debt, long-term debt, finance leases and interest payments on fixed-term debt and commercial paper. 2019 debt excludes lease liabilities.

(4) The company adopted IFRS 16 on January 1, 2019 using the modified retrospective transition approach and, therefore, prior periods have not been restated. Refer to note 5 for further information.

3) Credit Risk

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

A substantial portion of the company's accounts receivable are with customers in the oil and gas industry and are subject to normal industry credit risk. At December 31, 2019, substantially all of the company's trade receivables were current.

The company may be exposed to certain losses in the event that counterparties to derivative financial instruments are unable to meet the terms of the contracts. The company's exposure is limited to those counterparties holding derivative contracts owing to the company at the reporting date. At December 31, 2019, the company's exposure was $1 737 million (December 31, 2018 – $1 599 million).

27. CAPITAL STRUCTURE FINANCIAL POLICIES

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

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

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

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

The company's financial covenant is reviewed regularly and controls are in place to maintain compliance with the covenant. The company complied with financial covenants for the years ended December 31, 2019 and 2018. The company's financial measures, as set out in the following schedule, were unchanged from 2018. The company believes that achieving its capital target helps to provide the company access to capital at a reasonable cost by maintaining solid investment grade credit ratings. The company operates in a fluctuating business environment and ratios may periodically fall outside of management's targets. The company addresses these fluctuations by capital expenditure reductions and sales of non-core assets to ensure net debt achieves management's targets.

($ millions)	Capital Measure Target	**December 31, 2019**	December 31, 2018
Components of ratios			
Short-term debt		**2 155**	3 231
Current portion of long-term debt		**—**	229
Current portion of long-term lease liabilities		**310**	—
Long-term debt		**12 884**	13 890
Long-term lease liabilities		**2 621**	—
Total debt		**17 970**	17 350
Less: Cash and cash equivalents		**1 960**	2 221
Net debt		**16 010**	15 129
Shareholders' equity		**42 042**	44 005
Total capitalization (total debt plus shareholders' equity)		**60 012**	61 355
Funds from operations [(1)]		**10 818**	10 172
Net debt to funds from operations	<3.0 times	**1.5**	1.5
Total debt to total debt plus shareholders' equity	20% – 35%	**30%**	28%

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

28. JOINT ARRANGEMENTS

Joint Operations

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

Material Joint Operations	Principal Activity	Country of Incorporation and Principal Place of Business	Ownership % 2019	Ownership % 2018
Oil Sands				
Operated by Suncor:				
Fort Hills Energy Limited Partnership	Oil sands development	Canada	54.11	54.11
Meadow Creek	Oil sands development	Canada	75.00	75.00
Non-operated:				
Syncrude	Oil sands development	Canada	58.74	58.74
Exploration and Production				
Operated by Suncor:				
Terra Nova	Oil and gas production	Canada	37.68	37.68
Non-operated:				
Buzzard	Oil and gas production	United Kingdom	29.89	29.89
Fenja Development JV	Oil and gas production	Norway	17.50	17.50
Golden Eagle Area Development	Oil and gas production	United Kingdom	26.69	26.69
Hibernia and the Hibernia South Extension Unit	Oil and gas production	Canada	19.19-20.00	19.19-20.00
Hebron	Oil and gas production	Canada	21.03	21.03
Harouge Oil Operations	Oil and gas production	Libya	49.00	49.00
North Sea Rosebank Project	Oil and gas production	United Kingdom	40.00	40.00
Oda	Oil and gas production	Norway	30.00	30.00
White Rose and the White Rose Extensions	Oil and gas production	Canada	26.13-27.50	26.13-27.50

Joint Ventures and Associates

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

	Joint ventures		Associates	
($ millions)	**2019**	2018	**2019**	2018
Net (loss) earnings	**(7)**	11	**—**	(19)
Other comprehensive income	**—**	—	**—**	—
Total comprehensive (loss) income	**(7)**	11	**—**	(19)
Carrying amount as at December 31	**68**	75	**76**	110

29. SUBSIDIARIES

Material subsidiaries, each of which is wholly owned, either directly or indirectly, by the company as at December 31, 2019 are shown below:

Material Subsidiaries	Principal Activity
Canadian Operations	
Suncor Energy Oil Sands Limited Partnership	This partnership holds most of the company's Oil Sands operations assets.
Suncor Energy Ventures Corporation	A subsidiary which indirectly owns a 36.74% ownership in the Syncrude joint operation.
Suncor Energy Ventures Partnership	A subsidiary which owns a 22% ownership in the Syncrude joint operation.
Suncor Energy Products Partnership	This partnership holds substantially all of the company's Canadian refining and marketing assets.
Suncor Energy Marketing Inc.	Through this subsidiary, production from the upstream Canadian businesses is marketed. This subsidiary also administers Suncor's energy trading activities and power business, markets certain third-party products, procures crude oil feedstock and natural gas for its downstream business, and procures and markets natural gas liquids (NGLs) and liquefied petroleum gas (LPG) for its downstream business.
U.S. Operations	
Suncor Energy (U.S.A.) Marketing Inc.	A subsidiary that procures, markets and trades crude oil, in addition to procuring crude oil feedstock for the company's refining operations.
Suncor Energy (U.S.A.) Inc.	A subsidiary through which the company's U.S. refining and marketing operations are conducted.
International Operations	
Suncor Energy UK Limited	A subsidiary through which the majority of the company's North Sea operations are conducted.

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

30. RELATED PARTY DISCLOSURES

Related Party Transactions

The company enters into transactions with related parties in the normal course of business, which includes purchases of feedstock, distribution of refined products, and sale of refined products and byproducts. These transactions are with joint ventures and associated entities in the company's Refining and Marketing operations, including pipeline, refined product and petrochemical companies. A summary of the significant related party transactions as at and for the year ended December 31, 2019 and 2018 are as follows:

($ millions)	2019	2018
Sales[1]	**676**	723
Purchases	**215**	237
Accounts receivable	**38**	33
Accounts payable and accrued liabilities	**19**	15

(1) Includes sales to Parachem Chemicals Inc. of $269 million (2018 – $338 million).

Compensation of Key Management Personnel

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

($ millions)	2019	2018
Salaries and other short-term benefits	**14**	15
Pension and other post-retirement benefits	**3**	5
Share-based compensation	**47**	32
	64	52

31. COMMITMENTS, CONTINGENCIES AND GUARANTEES

(a) Commitments

Future payments under the company's commitments, including service arrangements for pipeline transportation agreements and for other property and equipment, are as follows:

	Payment Due by Period						
($ millions)	2020	2021	2022	2023	2024	Thereafter	**Total**
Commitments							
Product transportation and storage	1 083	1 034	992	1 076	1 068	9 470	**14 723**
Energy services	164	150	180	121	61	129	**805**
Exploration work commitments	7	44	—	—	—	465	**516**
Other	525	188	133	118	100	485	**1 549**
	1 779	1 416	1 305	1 315	1 229	10 549	**17 593**

The company has also entered into a pipeline commitment of $5.9 billion with a contract term of 20 years, which is awaiting regulatory approval.

In addition to the commitments in the above table, the company has other obligations for goods and services and raw materials entered into in the normal course of business, which may terminate on short notice. Such obligations include commodity purchase obligations which are transacted at market prices.

(b) Contingencies

Legal and Environmental Contingent Liabilities

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

The company may also have environmental contingent liabilities, beyond decommissioning and restoration liabilities (recognized in note 23), which are reviewed individually and are reflected in the company's consolidated financial statements if material and more likely than not to be incurred. These contingent environmental liabilities primarily relate to the mitigation of contamination at sites where the company has had operations. For any unrecognized environmental contingencies, the company believes that any liabilities that might arise pertaining to such matters would not have a material effect on its consolidated financial position.

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

(c) Guarantees

At December 31, 2019, the company has provided loan guarantees to certain retail licensees and wholesale marketers. Suncor's maximum potential amount payable under these loan guarantees is $125 million.

The company has also agreed to indemnify holders of all notes and debentures and the company's credit facility lenders (see note 20) for added costs relating to withholding taxes. Similar indemnity terms apply to certain facility and equipment leases. There is no limit to the maximum amount payable under these indemnification agreements. The company is unable to determine the maximum potential amount payable as government regulations and legislation are subject to change without notice. Under these agreements, the company has the option to redeem or terminate these contracts if additional costs are incurred.

The company also has guaranteed its working-interest share of certain joint operation undertakings related to transportation services agreements entered into with third parties. The guaranteed amount is limited to the company's share in the joint arrangement. As at December 31, 2019, the probability is remote that these guarantee commitments will impact the company.

32. ACQUISITION OF ADDITIONAL OWNERSHIP INTEREST IN THE SYNCRUDE PROJECT

On February 23, 2018, Suncor completed the purchase of an additional 5% working interest in the Syncrude project from Mocal Energy Limited for $923 million cash. Suncor's share in the Syncrude project has increased to 58.74%.

The acquisition has been accounted for as a business combination using the acquisition method. The purchase price allocation is based on management's best estimates of fair values of Syncrude's assets and liabilities as at February 23, 2018.

($ millions)

Accounts receivable	2
Inventory	15
Property, plant and equipment	998
Exploration and evaluation	163
Total assets acquired	**1 178**
Accounts payable and accrued liabilities	(51)
Employee future benefits	(33)
Decommissioning provision	(169)
Deferred income taxes	(2)
Total liabilities assumed	**(255)**
Net assets acquired	**923**

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

The additional working interest in Syncrude contributed $270 million to gross revenues and a $7 million net loss to consolidated net earnings from the acquisition date to December 31, 2018.

Had the acquisition occurred on January 1, 2018, the additional working interest would have contributed an additional $64 million to gross revenues and $4 million to consolidated net earnings, which would have resulted in gross revenues of $39.66 billion and consolidated net earnings of $3.30 billion for the twelve months ended December 31, 2018.

33. FORT HILLS

During the first quarter of 2018, Suncor acquired an additional 1.05% interest in the Fort Hills project for consideration of $145 million. The additional interest was an outcome of the commercial dispute settlement agreement reached among the Fort Hills partners in December 2017. Teck Resources Limited (Teck) also acquired an additional 0.42% in the project. Suncor's share in the project has increased to 54.11% and Teck's share has increased to 21.31% with Total E&P Canada Ltd.'s share decreasing to 24.58%.

34. OTHER TRANSACTIONS

In the third quarter of 2019, the company recognized a gain on sale of $65 million ($48 million after-tax) in the Exploration and Production segment related to the sale of its non-core Australian assets.

On June 28, 2019, the company completed a transaction to sell its 37% equity interest in Canbriam Energy Inc. (Canbriam) and recognized a gain on sale for the full proceeds of $151 million ($139 million after-tax) in the Exploration and Production segment. The investment in Canbriam was acquired early in 2018 through the exchange of Suncor's northeast British Columbia mineral landholdings, including associated production, and consideration of $52 million.

During the first quarter of 2019, the company received $363 million in insurance proceeds for its Libyan assets ($264 million after-tax). The proceeds may be subject to a provisional repayment, which may be dependent on the future performance and cash flows from Suncor's Libyan assets.

On September 29, 2018, Suncor along with the other working-interest partners in the Joslyn Oil Sands Mining project, agreed to sell 100% of their respective working interests to Canadian Natural Resources Limited for gross proceeds of $225 million, $82.7 million, net to Suncor. Suncor held a 36.75% working interest in Joslyn prior to the transaction. The working-interest partners received cash proceeds of $100 million ($36.8 million, net to Suncor) upon closing, with the remaining $125 million ($45.9 million, net to Suncor) to be received in equal instalments over the next five years. As a result, Suncor has recorded a long-term receivable of $36.7 million within the Other Assets line item and the first instalment of $9.2 million is recorded within the Accounts Receivable line item. The transaction resulted in a gain of $83 million in the Oil Sands segment.

On May 31, 2018, the company completed the previously announced transaction to acquire a 17.5% interest in the Fenja development project in Norway from Faroe Petroleum Norge AS for acquisition costs of US$55 million (approximately $70 million), plus interim settlement costs of $22 million under the acquisition method. This project was sanctioned by its owners in December 2017.

QuickLinks

EXHIBIT 99-1

Audited Consolidated Financial Statements of Suncor Energy Inc. for the fiscal year ended December 31, 2019
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EXHIBIT 99-2

**Management's Discussion and Analysis for the fiscal year ended December 31, 2019,
dated February 26, 2020**

MANAGEMENT'S DISCUSSION AND ANALYSIS

February 26, 2020

This Management's Discussion and Analysis (this MD&A) should be read in conjunction with Suncor's December 31, 2019 audited Consolidated Financial Statements and the accompanying notes. Additional information about Suncor filed with Canadian securities regulatory authorities and the United States Securities and Exchange Commission (SEC), including quarterly and annual reports and Suncor's Annual Information Form dated February 26, 2020 (the 2019 AIF), which is also filed with the SEC under cover of Form 40-F, is available online at www.sedar.com, www.sec.gov and our website www.suncor.com. Information on or connected to our website, even if referred to in this MD&A, does not constitute part of this MD&A.

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

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Basis of Presentation

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

Effective January 1, 2019, the company adopted IFRS 16 *Leases* (IFRS 16), which replaced the previous leasing standard IAS 17 *Leases* (IAS 17), and requires the recognition of all leases on the balance sheet, with optional exemptions for short-term leases where the term is twelve months or less and for leases of low value. IFRS 16 effectively removes the classification of leases as either finance or operating leases and treats all leases as finance leases for lessees. The accounting treatment for lessors remains essentially unchanged, with the requirement to classify leases as either finance or operating. Please refer to note 5 in the company's December 31, 2019 audited Consolidated Financial Statements for further information. The company has selected the modified retrospective transition approach, electing to adjust opening retained earnings with no re-statement of comparative figures. As such, comparative information continues to be reported under IAS 17 and International Financial Reporting Interpretations Committee (IFRIC) 4.

All financial information is reported in Canadian dollars, unless otherwise noted. Production volumes, apart from Libya, are presented on a working-interest basis, before royalties, unless otherwise noted. Libyan production volumes are presented on an economic basis.

Beginning in 2019, results from the company's Energy Trading business have been included within each of the respective operating business segments to which the respective trading activity relates. The Energy Trading business was previously reported within the Corporate, Energy Trading and Eliminations segment. Prior periods have been restated to reflect this change.

Also beginning in 2019, the company revised the classification of its capital expenditures into "asset sustainment and maintenance" and "economic investment" to better reflect the types of capital investments being made by the company. There is no impact to overall capital expenditures, and comparative periods have been restated to reflect this change. Refer to the Capital Investment Update section of this MD&A for further details.

Non-GAAP Financial Measures

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

Measurement Conversions

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

Common Abbreviations

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

Risks and Forward-Looking Information

The company's business, reserves, financial condition and results of operations may be affected by a number of factors, including, but not limited to, the factors described in the Risk Factors section of this MD&A.

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

1. FINANCIAL AND OPERATING SUMMARY

Financial Summary

Year ended December 31 ($ millions, except per share amounts)	2019	2018	2017
Gross revenues	**39 866**	39 592	32 885
Royalties	**(1 522)**	(1 050)	(931)
Operating revenues, net of royalties	**38 344**	38 542	31 954
Net earnings	**2 899**	3 293	4 458
per common share – basic	**1.86**	2.03	2.68
per common share – diluted	**1.86**	2.02	2.68
Operating earnings (1)	**4 358**	4 312	3 188
per common share – basic	**2.80**	2.65	1.92
Funds from operations (1)	**10 818**	10 172	9 139
per common share – basic	**6.94**	6.27	5.50
Cash flow provided by operating activities	**10 421**	10 580	8 966
per common share – basic	**6.69**	6.54	5.40
Dividends paid on common shares	**2 614**	2 333	2 124
per common share – basic	**1.68**	1.44	1.28
Weighted average number of common shares in millions – basic	**1 559**	1 623	1 661
Weighted average number of common shares in millions – diluted	**1 561**	1 629	1 665
ROCE (1) (%)	**4.9**	8.0	6.7
ROCE (1)(2) (%), excluding major projects in progress	**5.1**	8.2	8.6
Capital expenditures (3)	**5 436**	5 250	5 822
Asset sustainment and maintenance	**3 227**	3 347	2 557
Economic investment	**2 209**	1 903	3 265
Discretionary free funds flow (1)	**4 914**	4 432	4 415
Balance sheet (at December 31)			
Total assets	**89 435**	89 579	89 494
Net debt (4)(5)	**16 010**	15 129	12 907
Total liabilities	**47 393**	45 574	44 111

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

(2) Excludes capitalized costs related to major projects in progress. ROCE excluding major projects in progress would have been 8.6% in 2019, excluding the impacts of impairments of $3.352 billion and the impacts of a $1.116 billion deferred tax recovery relating to a change in the Alberta corporate income tax rate.

(3) Excludes capitalized interest of $122 million in 2019, $156 million in 2018, and $729 million in 2017, and now reflects the company's revised capital expenditure classification, with prior periods having been restated for this change. Refer to the Capital Investment Update section of this MD&A for further details.

(4) Net debt is equal to total debt less cash and cash equivalents. Total debt includes short-term debt, current portion of long-term debt, current portion of long-term lease liabilities, long-term debt, and long-term lease liabilities.

(5) 2018 and 2017 exclude the impact of IFRS 16, which was prospectively adopted on January 1, 2019, in accordance with the standard, adding $1.792 billion at December 31, 2019 to net debt.

Operating Summary

Year ended December 31	2019	2018	2017
Production volumes (mboe/d)			
Oil Sands	**670.4**	628.6	563.7
Exploration and Production	**106.8**	103.4	121.6
Total	**777.2**	732.0	685.3
Average price realizations [1] ($/boe)			
Oil Sands operations	**62.87**	54.91	54.26
Fort Hills	**48.96**	38.47	—
Syncrude	**73.45**	70.19	66.05
Exploration and Production	**82.92**	86.96	66.20
Refinery crude oil processed (mbbls/d)	**438.9**	430.8	441.2
Refinery utilization [2] (%)			
Eastern North America	**92**	94	93
Western North America	**98**	93	98
Total	**95**	93	96
Refining margin [3] ($/bbl)	**33.15**	34.50	24.20

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

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

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

Segment Summary [1]

Year ended December 31 ($ millions)	2019	2018	2017
Net (loss) earnings			
Oil Sands	**(427)**	945	994
Exploration and Production	**1 005**	807	721
Refining and Marketing	**3 000**	3 154	2 622
Corporate and Eliminations	**(679)**	(1 613)	121
Total	**2 899**	3 293	4 458
Operating earnings (loss) [2]			
Oil Sands	**1 622**	885	939
Exploration and Production	**1 141**	897	735
Refining and Marketing	**2 912**	3 154	2 128
Corporate and Eliminations	**(1 317)**	(624)	(614)
Total	**4 358**	4 312	3 188
Funds from (used in) operations [2]			
Oil Sands	**6 061**	4 964	4 734
Exploration and Production	**2 143**	1 779	1 756
Refining and Marketing	**3 863**	3 798	2 823
Corporate and Eliminations	**(1 249)**	(369)	(174)
Total funds from operations	**10 818**	10 172	9 139

Change in non-cash working capital	**(397)**	408	(173)
Cash flow provided by operating activities	**10 421**	10 580	8 966

(1) 2018 and 2017 have been restated to reflect the change to the company's segmented presentation of its Energy Trading business, with no impact on overall consolidated results. The Energy Trading business is now included within each of the respective operating business segments to which the respective trading activity relates. Suncor's Energy Trading business was previously reported within the Corporate Energy Trading and Eliminations segment.

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

2. SUNCOR OVERVIEW

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

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

Suncor's Strategy

Delivering competitive and sustainable returns to shareholders is a top priority of the company and we aim to maximize shareholder returns by focusing on our operational excellence, capital discipline through investment in high-value projects, and our commitment to environmental stewardship and sustainability. In an industry that has experienced volatility in recent years, we believe that Suncor is well positioned to succeed due to the company's competitive advantages: financial strength, including our ability to consistently generate free funds flow across a wide range of business environments, a highly efficient, tightly integrated suite of assets, an industry-leading long-life, low-decline oil sands reserves base, an offshore business that provides geographically diversified cash flow, and our investment in sustainability, technology and innovation.

Key components of Suncor's strategy include:

- Free funds flow growth through high-return investments – Suncor's growth and development plan is focused on projects and initiatives that are expected to create long-term value for the company through structural free funds flow growth. The company's significant long-life, low-decline reserves base combined with our industry expertise allows the company to execute improvement strategies at existing assets, such as debottlenecks and the deployment of autonomous haul trucks, that are expected to generate additional value for years to come. In addition, the company's regional oil sands advantage provides the company with the economies of scale required to realize synergies between assets and further develop our in situ resources in a low-cost manner under the company's replication strategy.

- Optimize value through integration and secured market access – From the ground to the gas station, Suncor optimizes profit along each step of the value chain through integration of the company's oil sands assets with its midstream and refining assets. This integration helps to significantly shield Suncor from the effects of western Canadian crude price differentials, and our midstream and marketing assets provide the logistical flexibility to move production to a wide range of markets. Through this midstream and marketing network and our geographical diversity, the company receives global-based pricing for the majority of its production.

- Achieve industry-leading unit costs in each business segment – Suncor aims to get the most out of our assets through a focus on operational excellence, which means operating in a way that is safe, reliable, cost-efficient and environmentally responsible. Driving down costs and a continued focus on improved productivity and reliability will help us achieve maximum value from our operations. With the Government of Alberta's imposition of mandatory production curtailments in 2019, the company's short-term focus in Oil Sands has shifted from maximizing production to maximizing margin from each barrel produced, resulting in higher production costs per barrel but optimizing the cash generation from our Oil Sands assets.

- Be an industry leader in sustainable development – Suncor is focused on triple bottom line sustainability, which means leadership and industry collaboration in environmental performance, social responsibility and creating a strong economy. We believe that Suncor's growth will be fuelled by investments in lower carbon energy, and we have made such investments a key priority in achieving our sustainable development goals.

- Technology and people-enabled – Suncor is focused on shifting our culture and leveraging technology to improve performance and reliability which are central to our operational excellence journey. Unleashing the full potential of our people and technology will be critical in achieving our environmental, operational and financial goals.

2019 Highlights

Suncor generated a record $10.8 billion in funds from operations[(1)] in 2019, reflecting the ability of our integrated business to deliver strong results across a wide range of market conditions.

- In 2019, Suncor achieved record funds from operations of $10.818 billion, compared to $10.172 billion in 2018, and marked the second consecutive year above $10 billion.
- Cash flow provided by operating activities, which includes changes in non-cash working capital, was $10.421 billion in 2019, compared to $10.580 billion in 2018.
- Operating earnings[(1)] in 2019 were $4.358 billion, compared to $4.312 billion in 2018.
- Net earnings for 2019 were $2.899 billion, compared to $3.293 billion in 2018. In 2019, net earnings included non-cash asset impairment charges of $3.352 billion after-tax primarily due to lower forecasted heavy oil prices for Fort Hills and higher capital cost estimates for the West White Rose Project.

Suncor returned $4.9 billion in dividends and share repurchases to shareholders in 2019, representing 45% of total funds from operations, demonstrating our commitment to shareholder returns.

- In 2019, the company distributed $2.614 billion in dividends to shareholders, marking the 17 th consecutive year of dividend increases for Suncor.
- The company repurchased $2.274 billion of its own common shares for cancellation during 2019. Since May 2017, the company has repurchased over 9% of its outstanding common shares.
- Suncor reduced its debt by $425 million, further improving the company's liquidity and balance sheet flexibility.
- Subsequent to the end of the year, Suncor's Board of Directors approved a quarterly dividend of $0.465 per common share, an increase of 11%, to be paid in the first quarter of 2020 and also approved the renewal of its share repurchase program of up to $2.0 billion beginning March 1, 2020.

Oil Sands production increased 7%, despite being limited by the Government of Alberta's mandatory production curtailments, with a continued focus on operational excellence and improved reliability.

- In 2019, the company achieved an SCO production record of 485,600 bbls/d across its Oil Sands assets while minimizing the impacts of mandatory production curtailments. During 2019, Suncor demonstrated the value of the company's asset integration and flexibility by shifting our focus to value over volume, optimization of product mix and transferring production quotas among its assets, in addition to purchasing third-party credits, to minimize the impacts of mandatory production curtailments.
    - Oil Sands operations increased its production of higher value SCO to 313,300 bbls/d and achieved upgrader utilization of 90%, compared to SCO production of 280,300 bbls/d and upgrader utilization of 80% in the prior year.
    - Syncrude reached three billion barrels of production and achieved the second best year of production in the history of the asset, due to improved upgrader reliability and despite mandatory production curtailments. In 2019, Suncor's share of Syncrude production was 172,300 bbls/d with 85% utilization, compared to 144,200 bbls/d and 70% utilization in the prior year. Syncrude cash operating costs per barrel[(1)] decreased approximately 20%, to $37.95 in 2019, from the prior year.
- Fort Hills production increased to 85,300 bbls/d in 2019, compared to 66,100 bbls/d in the prior year. The ramp up of Fort Hills operations throughout 2018 drove the increase in production, partially offset by mandatory production curtailments. Fort Hills cash operating costs per barrel[(1)] averaged $26.15 in 2019, compared to $31.20 in 2018, reflecting the impact of increased production.

(1) Funds from (used in) operations, operating earnings (loss), Syncrude cash operating costs and Fort Hills cash operating costs are Non-GAAP financial measures. See the Advisories – Non-GAAP Financial Measures section of this MD&A.

Exploration and Production (E&P) increased production with Hebron reaching nameplate ahead of schedule and first oil from Oda.

- Hebron reached nameplate production ahead of schedule in 2019, with six new production wells coming online during the year. Production at Hebron averaged 23,500 bbls/d in 2019.
- First oil was achieved ahead of schedule at Oda, with production averaging 3,700 boe/d in 2019, and averaging 7,800 boe/d in the fourth quarter of 2019.
- In 2019, the company sanctioned the Terra Nova asset life extension (ALE) project, which is expected to extend the life of Terra Nova by approximately a decade and is planned for execution by the end of 2020.

Refinery and Marketing (R&M) segment achieved new records and continued to deliver strong results in 2019.

- R&M achieved record funds from operations of $3.863 billion in 2019, delivering crude throughput of 438,900 bbls/d compared to funds from operations of $3.798 billion and crude throughput of 430,800 bbls/d in

the prior year. Average refinery utilization was 95% in 2019, compared with 93% in 2018, reflecting the company's continued focus on operational excellence.

- Refined product sales were 539,400 bbls/d, with record volumes sold in the marketing channels in 2019, including a new annual record for Canadian retail sales.

Continued focus on free funds flow growth by investing in projects that are economically robust, sustainability minded and technologically progressive.

- Suncor announced that it is replacing its coke-fired boilers with a new cogeneration facility at its Oil Sands Base Plant. The cogeneration units are expected to provide reliable steam generation required for Suncor's extraction and upgrading operations and are expected to reduce the greenhouse gas (GHG) emissions intensity associated with steam production at its Oil Sands Base Plant by approximately 25%. The project is estimated to cost $1.4 billion and is expected to be in service in the second half of 2023.

- In 2019, construction began on interconnecting pipelines between Suncor's Oil Sands Base Plant and Syncrude in anticipation of an in-service date in the second half of 2020. The bi-directional pipelines will enhance integration between these assets and is expected to increase reliability at Syncrude.

- The company continued to invest in clean energy by sanctioning the Forty Mile Wind Power Project, which is expected to drive value through sustainable low-carbon power generation and retention of the generated carbon credits for utilization in Suncor's upstream business. In addition, the company invested in clean technology, including a $73 million equity investment in Enerkem Inc., a waste-to-biofuels and chemicals producer.

- Suncor continued to advance the implementation of autonomous haul systems (AHS), tailings technology advancements, and accelerated our digital technology adoption at Fort Hills and Oil Sands operations.

- Suncor advanced its sustainability and technology initiatives by completing its coast-to-coast network of fast-charging electric vehicle stations across Canada in 2019.

3. FINANCIAL INFORMATION

Net Earnings

Suncor's net earnings in 2019 were $2.899 billion, compared to $3.293 billion in 2018. Net earnings were impacted by the same factors that influenced operating earnings, which are described below. Other items affecting net earnings in 2019 and 2018 included:

- During 2019, the company recorded non-cash after-tax impairment charges of $2.803 billion on its share of Fort Hills assets, in the Oil Sands segment, due to a decline in forecasted heavy crude oil prices and $393 million against White Rose, in the E&P segment, due to increased capital cost estimates at the West White Rose Project.
- The after-tax unrealized foreign exchange gain on the revaluation of U.S. dollar denominated debt was $590 million in 2019, compared to an after-tax loss of $989 million in 2018.
- In 2019, Suncor sold its 37% interest in Canbriam Energy Inc. (Canbriam), a private natural gas company, for total proceeds and an equivalent gain of $151 million ($139 million after-tax).
- In 2019, the company recorded an after-tax gain of $48 million in the E&P segment related to the sale of certain non-core assets.
- In 2019, the company recorded a $1.116 billion deferred income tax recovery associated with the Government of Alberta's enactment of legislation for a staged reduction of the corporate income tax rate from 12% to 8% over the next four years.
- In 2018, the company recorded a net non-cash loss of $90 million, after-tax, in the E&P segment related to an asset exchange with Canbriam, as a result of the decline in benchmark natural gas prices in B.C.
- In 2018, the company recorded an after-tax gain of $60 million in the Oil Sands segment on the sale of the company's interest in the Joslyn oil sands mining project.

Operating Earnings

Consolidated Operating Earnings Reconciliation (1)

Year ended December 31 ($ millions)	2019	2018	2017
Net earnings	**2 899**	3 293	4 458
Asset impairments	**3 352**	—	—
Unrealized foreign exchange (gain) loss on U.S. dollar denominated debt	**(590)**	989	(702)
(Gain) on significant disposals and loss on equity investment (2)	**(187)**	30	(437)
Impact of income tax adjustments on deferred income taxes (3)	**(1 116)**	—	(124)
Loss on interest rate swaps (4)	**—**	—	20
Non-cash loss on early payment of long-term debt (5)	**—**	—	28
Recognition of property damage insurance proceeds (6)	**—**	—	(55)
Operating earnings (1)	**4 358**	4 312	3 188

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

(2) In 2017, the company recorded a $354 million after-tax gain in the R&M segment related to the sale of the company's lubricants business, and an after-tax gain of $83 million in the Corporate and Eliminations segment related to the sale of the company's interest in the Cedar Point wind facility.

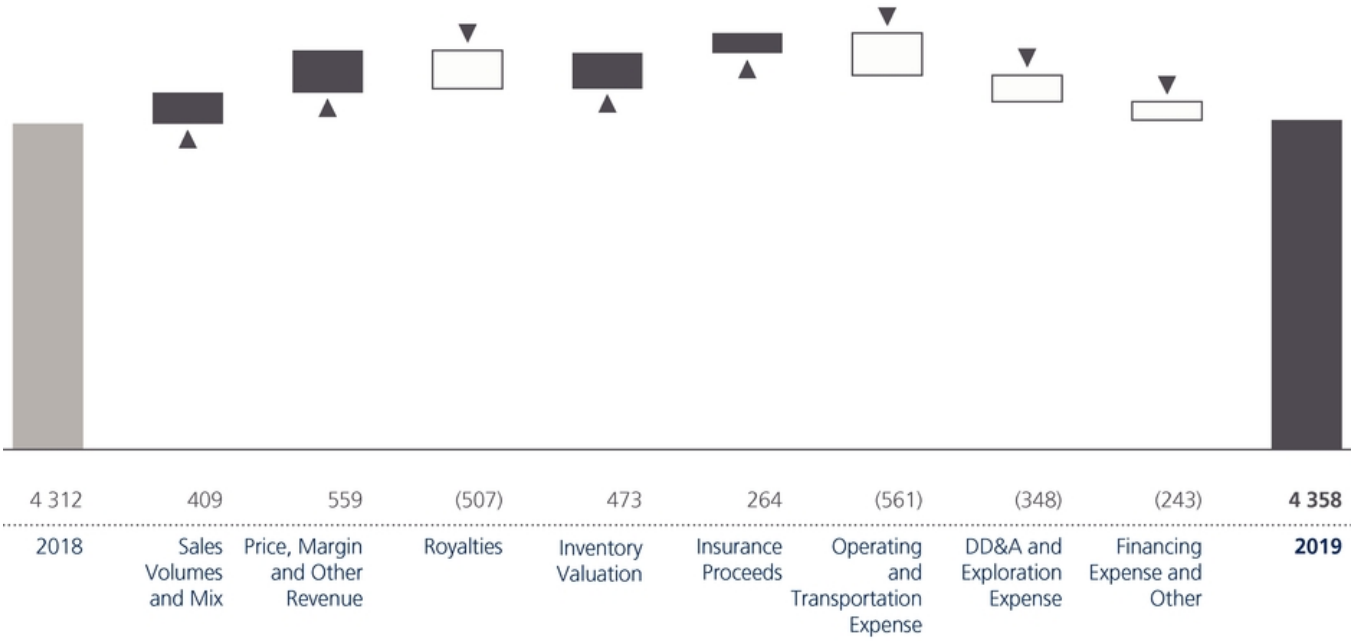
(3) In 2017, the company recorded an adjustment to its deferred income taxes of $124 million related to tax reform legislation in the U.S., with the most significant impact resulting from a decrease in the corporate income tax rate from 35% to 21%.

(4) Loss on forward interest rate swaps associated with issued debt, due to changes in long-term interest rates, in the Corporate and Eliminations segment.

(5) Charges associated with the early repayment of debt, net of associated realized foreign currency hedges, in the Corporate and Eliminations segment.

(6) In 2017, the company received after-tax property damage insurance proceeds of $55 million ($76 million before tax) related to a facility incident at Syncrude, in the Oil Sands segment.

Bridge Analysis of Consolidated Operating Earnings ($ millions)[1]



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

Suncor's consolidated operating earnings in 2019 were $4.358 billion, compared to $4.312 billion in the prior year. The increase was primarily a result of improved western Canadian crude oil differentials, including a substantial narrowing of heavy crude and SCO differentials, which more than offset lower benchmark pricing from the prior year. This led to an increase in Oil Sands price realizations and a net favourable inventory valuation change on crude feedstock costs, partially offset by increased deferral of profit on crude oil sales to R&M, and lower refining margins. Operating earnings in 2019 were also positively impacted by higher overall upstream production, attributed to improved reliability at Syncrude and the ramp up of Fort Hills and Hebron throughout 2019, partially offset by the impact of the Government of Alberta's mandatory production curtailments.

These factors were partially offset by an increase in expenses associated with Suncor's increased production in 2019. DD&A was further impacted by transition to IFRS 16, which also increased financing expenses.

Cash Flow Provided by Operating Activities and Funds from Operations

Consolidated funds from operations for 2019 were $10.818 billion, compared to $10.172 billion in 2018, and were impacted by the same factors as operating earnings described above, excluding the impact of DD&A expense.

Cash flow provided by operating activities, which includes changes in non-cash working capital, was $10.421 billion in 2019, compared to $10.580 billion in 2018, as the current year included a use of cash in working capital, compared to a source of cash in working capital in the prior year which was due to a decrease in accounts receivable balances and refinery inventory value associated with the declining price environment in the second half of 2018.

Results for 2018 Compared with 2017

Net earnings in 2018 were $3.293 billion, compared to $4.458 billion in 2017. The decrease in net earnings was impacted by the same factors impacting operating earnings described below, as well as an after-tax unrealized foreign exchange loss on the revaluation of U.S. dollar denominated debt in 2018, compared to an after-tax unrealized foreign exchange gain in 2017.

Operating earnings were $4.312 billion in 2018, compared to $3.188 billion in 2017. The increase was primarily due to improved overall benchmark crude pricing, increased refining margins, higher overall upstream production, primarily attributed to the ramp up of Fort Hills and Hebron and the increased working interest in Syncrude acquired in early 2018, as well as improved energy trading earnings. These factors were partially offset by an increase in expenses associated with the expansion of the company's production in 2018, an increase in maintenance expenditures at Syncrude and Oil Sands operations resulting from an increase in planned and unplanned maintenance, a decrease in the capitalization of borrowing costs with the commissioning of the company's major growth projects, as well as a net unfavourable inventory valuation change on declining crude feedstock costs at the end of 2018.

Consolidated funds from operations for 2018 were $10.172 billion, compared to $9.139 billion in 2017. Funds from operations were impacted by the same factors as operating earnings described above.

Cash flow provided by operating activities, which includes changes in non-cash working capital, was $10.580 billion in 2018, compared to $8.966 billion in 2017, and reflected a source of cash from the company's working capital balances in 2018, compared to a use of cash in 2017, as a result of lower year end benchmarks.

Business Environment

Commodity prices, refining crack spreads and foreign exchange rates are important factors that affect the results of Suncor's operations.

Average for the year ended December 31	**2019**	2018	2017
WTI crude oil at Cushing (US$/bbl)	**57.05**	64.80	50.95
Dated Brent Crude (US$/bbl)	**64.30**	71.05	54.25
Dated Brent/Maya crude oil FOB price differential (US$/bbl)	**6.45**	9.10	7.70
MSW at Edmonton (Cdn$/bbl)	**69.20**	69.30	63.20
WCS at Hardisty (US$/bbl)	**44.25**	38.50	38.95
Light/heavy differential for WTI at Cushing less WCS at Hardisty (US$/bbl)	**(12.80)**	(26.30)	(11.95)
SYN-WTI differential (US$/bbl)	**(0.60)**	(6.15)	(1.27)
Condensate at Edmonton (US$/bbl)	**52.85**	61.05	51.55
Natural gas (Alberta spot) at AECO (Cdn$/mcf)	**1.75**	1.50	2.15
Alberta Power Pool Price (Cdn$/MWh)	**54.95**	50.20	22.15
New York Harbor 2-1-1 crack (1) (US$/bbl)	**19.90**	19.40	18.20
Chicago 2-1-1 crack (1) (US$/bbl)	**17.05**	17.40	16.80
Portland 2-1-1 crack (1) (US$/bbl)	**24.55**	24.00	22.50
Gulf Coast 2-1-1 crack (1) (US$/bbl)	**19.15**	18.40	17.70
Exchange rate (US$/Cdn$)	**0.75**	0.77	0.77
Exchange rate (end of period) (US$/Cdn$)	**0.77**	0.73	0.80

(1) 2-1-1 crack spreads are indicators of the refining margin generated by converting two barrels of WTI into one barrel of gasoline and one barrel of diesel. The company previously quoted 3-2-1 crack margin benchmarks based on wider use and familiarity with these benchmarks and, although the 3-2-1 crack spread is more commonly quoted, the company's refinery production is better aligned with a 2-1-1 crack spread, which better reflects the approximate composition of Suncor's overall refined product mix. The crack spreads presented here generally approximate the regions into which the company sells refined products through retail and wholesale channels.

Suncor's sweet SCO price realizations are influenced primarily by the price of WTI at Cushing and by the supply and demand of sweet SCO from Western Canada, which influences SCO differentials. Price realizations for sweet SCO were favourably impacted by a significant narrowing of SCO differentials, partially offset by a decrease in WTI at Cushing to US$57.05/bbl in 2019, from US$64.80/bbl in 2018.

Suncor also produces a specific grade of sour SCO, the price realizations for which are influenced by various crude benchmarks including, but not limited to, MSW at Edmonton and WCS at Hardisty, and which can also be affected by prices negotiated for spot sales. Prices for MSW at Edmonton in 2019 were relatively unchanged from 2018, while WCS at Hardisty increased to US$44.25 in 2019 compared to US$38.50 in 2018, reflecting the impact of narrowing western Canadian heavy crude differentials, in part due to mandatory production curtailments in Alberta. Sweet and sour SCO differentials in 2019 were favourable when compared to 2018.

Bitumen production that Suncor does not upgrade is blended with diluent to facilitate delivery on pipeline systems. Net bitumen price realizations are therefore influenced by both prices for Canadian heavy crude oil (WCS at Hardisty is a common reference) and prices for diluent (Condensate at Edmonton and SCO) and pipeline tolls. Bitumen price realizations can also be affected by bitumen quality and spot sales. Bitumen prices were favourably impacted by narrower heavy crude oil differentials in 2019.

Suncor's price realizations for production from East Coast Canada and E&P International assets are influenced primarily by the price for Brent crude, which averaged US$64.30/bbl in 2019, compared to US$71.05/bbl in 2018. Due to the nature of cargo shipments at the company's offshore assets, the timing associated with bulk cargo sales can result in price realizations that deviate from the average benchmark price over the period.

Suncor's refining margins are primarily influenced by industry benchmark crack spreads and, although the 3-2-1 crack spread is more commonly quoted, the company's refinery

production is better aligned with a 2-1-1 crack spread, which more appropriately reflects the company's refined product mix of gasoline and distillates. Benchmark crack spreads are industry indicators approximating the gross margin on a barrel of crude oil that is refined to produce gasoline and distillates. More complex refineries can earn greater refining margins by processing less expensive, heavier crudes, or lighter crudes discounted relative to the WTI benchmark. Crack spreads do not necessarily reflect the margins of a specific refinery. Crack spreads quoted in the market are based on current crude feedstock prices whereas actual earnings are based on first-in, first-out (FIFO) inventory accounting, where a delay exists between the time that feedstock is purchased and when it is processed and sold to a third party. A FIFO loss normally reflects a declining price environment for crude oil and finished products, whereas FIFO gains reflect an increasing price environment for crude oil and finished products. Specific refinery margins are further impacted by actual crude purchase costs, refinery configuration, production mix and realized prices for refined products sales in markets unique to each refinery.

Natural gas used in Suncor's Oil Sands and Refining operations is primarily referenced to Alberta spot prices at AECO. The average AECO benchmark increased to $1.75/mcf in 2019, from $1.50/mcf in the prior year.

Excess electricity produced in Suncor's Oil Sands operations business is sold to the Alberta Electric System Operator, with the proceeds netted against the Oil Sands operations cash operating costs per barrel metric. The Alberta power pool price increased to an average of $54.95/MWh in 2019 from $50.20/MWh in the prior year.

The majority of Suncor's revenues from the sale of oil and natural gas commodities are based on prices that are determined by or referenced to U.S. dollar benchmark prices. The majority of Suncor's expenditures are realized in Canadian dollars. A decrease in the value of the Canadian dollar relative to the U.S. dollar will increase the revenues received from the sale of commodities. An increase in the value of the Canadian dollar relative to the U.S. dollar will decrease revenues received from the sale of commodities. In 2019, the Canadian dollar weakened in relation to the U.S. dollar as the average exchange rate decreased to US$0.75 per one Canadian dollar from US$0.77 per one Canadian dollar, which had a positive impact on price realizations for the company in 2019.

Conversely, some of Suncor's assets and liabilities, notably 65% of the company's debt, are denominated in U.S. dollars and translated to Suncor's reporting currency (Canadian dollars) at each balance sheet date. An increase in the value of the Canadian dollar relative to the U.S. dollar from the previous balance sheet date decreases the amount of Canadian dollars required to settle U.S. dollar denominated obligations.

Economic Sensitivities[1][2]

The following table illustrates the estimated effects that changes in certain factors would have had on 2019 net earnings and funds from operations [3] if the listed changes had occurred.

(Estimated change, in $ millions)	Net Earnings	Funds From Operations[3]
Crude oil +US$1.00/bbl	238	238
Natural gas +Cdn$0.10/mcf	(24)	(24)
WTI – narrowing light/heavy differential +US$1.00/bbl	23	23
2-1-1 crack spreads +US$1.00/bbl	153	153
Foreign exchange +$0.01 US$/Cdn$ related to operating activities [4]	(221)	(221)
Foreign exchange on U.S. dollar denominated debt +$0.01 US$/Cdn$	159	—

(1) Each line item in this table shows the effects of a change in that variable only, with other variables being held consistent.

(2) Changes for a variable imply that all such similar variables are impacted, such that Suncor's average price realizations increase uniformly. For instance, "Crude oil +US$1.00/bbl" implies that price realizations influenced by WTI, Brent, SCO, WCS, par crude at Edmonton and condensate all increase by US$1.00/bbl.

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

(4) Excludes the foreign exchange impact on U.S dollar denominated debt.

4. SEGMENT RESULTS AND ANALYSIS

Suncor has classified its operations into the following segments:

OIL SANDS

Suncor's Oil Sands segment, with assets located in the Athabasca oil sands of northeast Alberta, recovers bitumen from mining and in situ operations. Bitumen is either upgraded into SCO for refinery feedstock and diesel fuel, or blended with diluent for direct sale to market through the company's midstream infrastructure and its marketing activities. The Oil Sands segment includes:

- **Oil Sands operations** refer to Suncor's owned and operated mining, extraction, upgrading, in situ and related logistics, blending 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, energy, reclamation and storage facilities.
    - **In Situ** operations include oil sands bitumen production from Firebag and MacKay River and supporting infrastructure, including central processing facilities, cogeneration units, product transportation infrastructure, diluent import capabilities, storage assets and a cooling and blending facility. In Situ also includes development opportunities which may support future in situ production, including Meadow Creek (75%), Lewis (100%), OSLO (77.78%), various interests in Chard (25% to 50%), and a non-operated interest in Kirby (10%). In Situ production is either upgraded by Oil Sands Base, or blended with diluent and marketed directly to customers.
- **Fort Hills** includes Suncor's 54.11% interest in Fort Hills, which the company operates, and the East Tank Farm Development in which Suncor holds a 51% interest and operates.
- **Syncrude** refers to Suncor's 58.74% interest in the Syncrude oil sands mining and upgrading operation.

EXPLORATION AND PRODUCTION

Suncor's E&P segment consists of offshore operations off the east coast of Canada and in the North Sea, and onshore assets in 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), White Rose (27.5% in the base project and 26.125% in the extensions), and Hebron (21.034%). In addition, the company holds interests in several exploration licences and significant discovery licences offshore Newfoundland and Labrador. Previously, E&P Canada also included Suncor's 37% equity interest in Canbriam which was sold during the second quarter of 2019.
- **E&P International** operations include Suncor's non-operated interests in Buzzard (29.89%), the Golden Eagle Area Development (26.69%), Oda (30%), the Fenja project (17.5%), and the Rosebank future development project (40%). Buzzard, Golden Eagle, and Rosebank are located in the U.K. sector of the North Sea, while Oda and the Fenja project are located in the Norwegian North Sea and the Norwegian Sea, respectively. In addition, Suncor owns, pursuant to Exploration and Production Sharing Agreements (EPSAs), working interests in the exploration and development of oilfields in the Sirte Basin in Libya, although production in Libya remained partially shut in throughout 2019 due to continued political unrest. The timing of a return to normal operations in Libya remains uncertain. Suncor also owns, pursuant to a Production Sharing Contract (PSC), an interest in the Ebla gas development in Syria, which has been suspended, indefinitely, since 2011 due to political unrest in the country.

REFINING AND MARKETING

The R&M segment consists of two primary operations, the refining and supply and marketing operations discussed below, as well as the infrastructure supporting the marketing and supply of refined products, crude oil, natural gas, power and byproducts.

- **Refining and Supply** operations refine crude oil and intermediate feedstock into a wide range of petroleum and petrochemical products. Refining and Supply consists of:
    - **Eastern North America** operations include a 137,000 bbls/d refinery located in Montreal, Quebec and an 85,000 bbls/d refinery located in Sarnia, Ontario.
    - **Western North America** operations include a 142,000 bbls/d refinery located in Edmonton, Alberta and a 98,000 bbls/d refinery in 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

throughout Canada and the U.S., and the St. Clair ethanol plant in Ontario.

- **Marketing** operations sell refined petroleum products to retail, commercial and industrial customers through a combination of company-owned, Petro-Canada™ and Sunoco™ location and branded-dealers in Canada and other non-branded retail stations in the U.S., a nationwide commercial road transportation network in Canada, as well as a bulk sales channel in Canada.

CORPORATE AND ELIMINATIONS

The **Corporate and Eliminations** segment includes the company's investments in renewable energy projects, and other activities not directly attributable to any other operating segment.

- **Renewable Energy** includes interests in four wind farm operations in Ontario and Western Canada: Adelaide, Chin Chute, Magrath and Sunbridge, as well as the recently sanctioned Forty Mile Wind Power Project currently under construction.

- **Corporate** activities include stewardship of Suncor's debt and borrowing costs, expenses not allocated to the company's businesses, the company's captive insurance activities that insure a portion of the company's asset base and investments in clean technology.

- 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. The sale of product between the company's segments is primarily related to crude refining feedstock sold from Oil Sands to R&M.

OIL SANDS

2019 Highlights

- In 2019, the company achieved an SCO production record of 485,600 bbls/d across its Oil Sands assets. Suncor's curtailment optimization strategy maximized the value of the company's allotted barrels under the Government of Alberta's mandatory production curtailments program effective January 2019. The company was able to optimize the transfer of allotted curtailment credits among the company's assets and purchase third-party credits to maximize production of higher value SCO production, demonstrating our focus on value over volume.

    - Oil Sands operations increased SCO production to 313,300 bbls/d and achieved upgrader utilization of 90% in 2019, compared to 280,300 bbls/d and upgrader utilization of 80% in the prior year.

    - Syncrude celebrated its three billionth barrel of production and achieved the second best year of production in its history, despite mandatory production curtailments. Syncrude production of SCO was 172,300 bbls/d with 85% utilization, compared to 144,200 bbls/d and 70% utilization in the prior year, due to improved upgrader reliability and lower unplanned maintenance. Syncrude cash operating costs per barrel declined significantly to $37.95 in 2019, compared to $47.25 in the prior year, due to improved reliability and lower maintenance.

- Suncor's share of production from Fort Hills increased to 85,300 bbls/d, compared to 66,100 bbls/d in the prior year, due to the ramp up of operations throughout 2018, partially offset by mandatory production curtailments.

- In 2019, construction began on interconnecting pipelines between Suncor's Oil Sands Base Plant and Syncrude in anticipation of an in-service date in the second half of 2020. The bi-directional pipelines are expected to enhance integration between these assets and increase reliability at Syncrude.

- In 2019, Suncor announced a $1.4 billion investment in a new cogeneration facility at Oil Sands Base Plant to deliver low-carbon power generation and replace existing coke-fired boilers. This investment is expected to provide reliable steam generation while contributing to the company's environmental and incremental annual free funds flow growth goal.

Strategy and Investment Update

Suncor holds one of the largest resource positions in the Athabasca oil sands. Management is committed to delivering safe, reliable, low-cost production, while being leaders in growth, technical innovation and environmental sustainability. The company has developed a unique asset base within the oil sands and has established a regional advantage given the close proximity of the company's assets to one another. This collection of high-quality assets, combined with a long-life, low-decline reserves base and industry-leading expertise, provides the opportunity to continue to advance technology and innovation investments and high return growth projects while growing annual free funds flow.

The company's ability to leverage technology and innovation is at the core of our strategy supporting our financial, social and environmental goals. Investments to replace its coke-fired boilers with a cogeneration facility at its Oil Sands Base Plant is expected to provide reliable steam generation required for Suncor's extraction and upgrading, at a lower cost and with significantly lower carbon emissions. The facility is also expected to generate electricity that will be transmitted to Alberta's power grid, providing a lower carbon power alternative while delivering value to Suncor.

Additional technology projects, including the continued deployment of AHS, and innovative tailings technology advancements, including Permanent Aquatic Storage Structure, demonstrate the importance technology and innovation have in increasing efficiency and lowering operating costs while improving our environmental and safety performance.

Suncor remains committed to increasing reliability and enhancing the integration of our existing assets for profitable growth. The investment in the bi-directional interconnecting pipelines between Syncrude and Oil Sands Base Plant will provide increased operational flexibility, enabling higher reliability, utilization and profit optimization for all Syncrude partners. The pipelines are expected to be in service in the second half of 2020.

Cost management and capital discipline in Oil Sands will continue to be top priorities as the company expects to manage controllable operating costs through initiatives that include co-ordinated maintenance strategies, equipment standardization and the adoption of digital technologies. Capital discipline continues to focus on managing investment opportunities, including asset synergies and sustainability priorities, strategically investing in projects that are economically robust, sustainably minded and technologically progressive. With these factors in mind, the company has identified opportunities to debottleneck Firebag, including the completion of our emulsion handling project this year, integrate well pad development and expand our Solvent steam-assisted gravity drainage program. Our near-term expectation is to have actual Firebag production at nameplate capacity of 203,000 bbls/d in 2021, assuming no production curtailment, with the potential to add up to 30,000 bbls/d of lower capital intensity and lower carbon production by 2024-25.

Through Suncor's midstream and logistics network, the company secures market access, optimizes price realizations associated with the marketing of crude oil and byproducts and natural gas supply, manages inventory levels, and limits the impacts of external market factors, such as pipeline disruptions, lack of egress or outages at refining customers.

Financial Highlights[1]

Year ended December 31 ($ millions)	**2019**	2018	2017
Gross revenues	**18 347**	15 743	13 274
Less: Royalties	**(917)**	(398)	(355)
Operating revenues, net of royalties	**17 430**	15 345	12 919
Net (loss) earnings	**(427)**	945	994
Adjusted for:			
Asset impairment	**2 959**	—	—
Gain on significant disposal[2]	**—**	(60)	—
Insurance proceeds[3]	**—**	—	(55)
Impact of income tax rate adjustment on deferred taxes	**(910)**	—	—
Operating earnings[4]	**1 622**	885	939
Funds from operations[4]	**6 061**	4 964	4 734

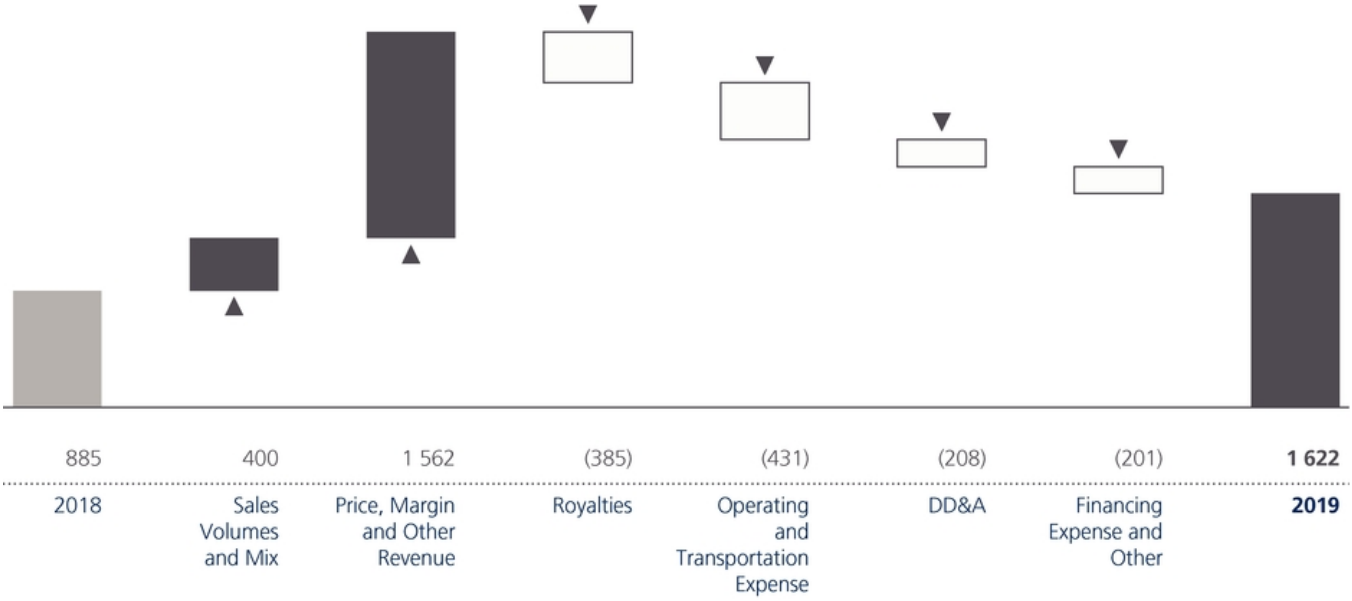
(1) 2018 and 2017 have been restated to reflect the change to the company's segmented presentation of its Energy Trading business, with no impact to overall consolidated results. The Energy Trading business is now included within each of the respective operating business segments to which the respective trading activity relates. Suncor's Energy Trading business was previously reported within the Corporate, Energy Trading and Eliminations segment.

(2) In 2018, the company recorded an after-tax gain of $60 million on the sale of the company's interest in the Joslyn oil sands mining project.

(3) In 2017, the company received after-tax property damage proceeds of $55 million related to a facility incident at Syncrude.

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

Bridge Analysis of Operating Earnings ($ millions)[1]



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

Operating earnings in Oil Sands operations were $1.622 billion in 2019, compared to $885 million in 2018. The increase in operating earnings is primarily due to improved western Canadian crude oil differentials, including a substantial narrowing of heavy crude and SCO differentials, which more than offset lower benchmark pricing from the prior year and resulted in higher Oil Sands price realizations. Strong Syncrude reliability and the ramp up of production at Fort Hills throughout 2018 contributed to the overall increase in Oil Sands production in 2019 compared to the prior year, despite being limited by mandatory production curtailments. Operating earnings were unfavourably impacted by higher operating costs, higher royalties and DD&A associated with the increase in production.

Oil Sands had a net loss of $427 million in 2019, compared to net earnings of $945 million in 2018, and was impacted by the same factors as operating earnings described above. In addition, 2019 net earnings included the impact of a non-cash impairment charge of $2.803 billion after-tax on the company's share of the Fort Hills assets, described below, partially offset by a one-time deferred income tax recovery of $910 million associated with a staged reduction to the Alberta corporate income tax rate of 1% each year from 2019 to 2022.

Funds from operations for the Oil Sands segment were $6.061 billion in 2019, compared to $4.964 billion in 2018, and were influenced by the same factors that impacted operating earnings, adjusted for the impact of non-cash DD&A.

Production Volumes[1]

Year ended December 31 (mbbls/d)	2019	2018	2017
Upgraded product (SCO and diesel)	**313.3**	280.3	317.7
In Situ non-upgraded bitumen	**99.5**	138.0	111.7
Total Oil Sands operations production	**412.8**	418.3	429.4
Fort Hills bitumen	**85.3**	66.1	—
Syncrude (sweet SCO and diesel)	**172.3**	144.2	134.3
Total	**670.4**	628.6	563.7

(1) Bitumen from Oil Sands Base operations is upgraded, while bitumen from In Situ operations is upgraded or sold directly to customers. Yields of SCO from Suncor's upgrading processes are approximately 79% of bitumen feedstock input. Yields of SCO from Syncrude's upgrading processes are approximately 85% of bitumen feedstock input.

Oil Sands operations production decreased to 412,800 bbls/d in 2019 from 418,300 bbls/d in 2018, primarily due to mandatory production curtailments. Mandatory production curtailments largely impacted the company's non-upgraded bitumen production and resulted in an increased yield loss as the company maximized production to its upgraders in order to produce higher value SCO. In 2019, SCO production increased to 313,300 bbls/d, with upgrader utilization of 90%, compared to SCO production of 280,300 bbls/d and upgrader utilization of 80% in the prior year, reflecting strong reliability in 2019 and reduced maintenance.

Fort Hills bitumen production increased to 85,300 bbls/d in 2019 from 66,100 bbls/d in 2018, due to the ramp up in production throughout 2018, partially offset by the impact of mandatory production curtailments. Fort Hills remains

adversely impacted by mandatory production curtailments due to the continued, disproportionate effect of curtailment as it is applied on a 2018 production basis when the asset was ramping up to full production rates. In 2019, the company was able to partially mitigate impacts of curtailment on production by internally transferring credits from Oil Sands operations during planned maintenance and purchasing third-party curtailment credits.

Suncor's share of Syncrude production increased to 172,300 bbls/d in 2019, compared to 144,200 bbls/d in 2018, marking the second best year of production in the asset's history, even with mandatory production curtailments. The increase is primarily due to strong reliability and lower maintenance resulting in upgrader utilization of 85% in 2019, compared to 70% in the prior year. In 2019, Syncrude was able to partially mitigate the impact of curtailment on production by purchasing curtailment credits from partners and third parties.

Sales Volumes and Mix

Year ended December 31 (mbbls/d)	**2019**	2018	2017
Oil Sands operations sales volumes			
Sweet SCO	**113.5**	96.1	107.9
Diesel	**26.0**	28.8	27.5
Sour SCO	**171.8**	162.6	183.6
Upgraded product (SCO)	**311.3**	287.5	319.0
In Situ non-upgraded bitumen	**101.4**	134.0	110.6
Oil Sands operations	**412.7**	421.5	429.6
Fort Hills bitumen	**86.1**	57.3	—
Syncrude sweet SCO	**172.3**	144.2	134.3
Total	**671.1**	623.0	563.9

Sales volumes for Oil Sands operations decreased to 412,700 bbls/d in 2019, compared to 421,500 bbls/d in 2018, reflecting the same factors impacting production volumes.

Bitumen sales at Fort Hills increased to 86,100 bbls/d, net to Suncor, in 2019, from 57,300 bbls/d in the prior year, consistent with the increase in production.

Bitumen Production from Operations

Year ended December 31	**2019**	2018	2017
Oil Sands Base			
Bitumen production (mbbls/d)	**289.9**	258.8	305.4
Bitumen ore mined (thousands of tonnes/day)	**434.8**	378.0	464.4
Bitumen ore grade quality (bbls/tonne)	**0.67**	0.68	0.66
In Situ			
Bitumen production – Firebag (mbbls/d)	**187.0**	204.0	181.5
Steam-to-oil ratio – Firebag	**2.7**	2.7	2.7
Bitumen production – MacKay River (mbbls/d)	**29.2**	36.0	31.1
Steam-to-oil ratio – MacKay River	**3.0**	2.9	3.1
Total In Situ bitumen production (mbbls/d)	**216.2**	240.0	212.6
Total Oil Sands operations bitumen production (mbbls/d)	**506.1**	498.8	518.0
Fort Hills			
Bitumen production (mbbls/d)	**85.3**	66.1	—
Bitumen from froth	**—**	1.3	—
Bitumen ore mined (thousands of tonnes/day)	**140.5**	106.2	—
Bitumen ore grade quality (bbls/tonne)	**0.61**	0.63	—
Syncrude			
Bitumen production (mbbls/d)	**205.4**	172.0	163.6

Bitumen ore mined (thousands of tonnes/day)	**330.5**	277.5	252.7
Bitumen ore grade quality (bbls/tonne)	**0.62**	0.62	0.63
Total Oil Sands bitumen production (mbbls/d)	**796.8**	738.2	681.6

Oil Sands operations bitumen production increased to 506,100 bbls/d in 2019, compared to 498,800 bbls/d in 2018. The increase is primarily due to strong upgrader reliability and the associated increase in mined bitumen volumes, partially offset by lower non-upgraded In Situ production due to mandatory production curtailments after maximizing the volume of Firebag bitumen upgraded into SCO.

Bitumen production at Syncrude increased in 2019 to 205,400 bbls/d from 172,000 bbls/d in 2018, and was impacted by the same factors as production described above.

Price Realizations

Year ended December 31 Net of transportation costs, but before royalties ($/bbl)	**2019**	2018	2017
Oil Sands operations			
SCO and diesel	**69.65**	68.97	61.47
Bitumen	**42.08**	24.70	33.47
Crude sales basket (all products)	**62.87**	54.91	54.26
Crude sales basket, relative to WTI	**(13.20)**	(29.24)	(11.91)
Fort Hills bitumen	**48.96**	38.47	—
Syncrude – sweet SCO	**73.45**	70.19	66.05
Syncrude, relative to WTI	**(2.62)**	(13.97)	(0.12)

Average price realizations at Oil Sands operations increased to $62.87/bbl in 2019 compared to $54.91/bbl in 2018, primarily due to the narrowing of heavy crude and SCO differentials resulting from mandatory production curtailments in the province of Alberta, and the impact of a weaker Canadian dollar, partially offset by a decrease in the WTI benchmark price.

Average price realizations for Fort Hills bitumen were $48.96/bbl in 2019 and were higher than In Situ bitumen realizations due to a higher proportion of sales being made in the U.S. mid-continent and the U.S. Gulf Coast, where Suncor is able to utilize its logistics network to access favourable pricing in the U.S. market, combined with the higher quality associated with paraffinic froth-treated bitumen produced at Fort Hills. Average price realizations were higher than the prior year due to the improved heavy crude oil differential and the impact of a weaker Canadian dollar, partially offset by a decrease in the WTI benchmark price.

Suncor's average price realization for Syncrude sales increased in 2019 to $73.45/bbl, compared to $70.19/bbl in 2018, due to narrower SCO differentials and the impact of a weaker Canadian dollar, partially offset by decreased WTI benchmark pricing.

Royalties

Royalties were higher in 2019 relative to 2018, primarily due to higher bitumen pricing and production volumes.

Expenses and Other Factors

Total operating and transportation expenses for 2019 were higher relative to 2018, as described in detail below. See the Cash Operating Costs section below for further details.

At Oil Sands operations, operating costs increased when compared to the prior year as a result of higher costs associated with increased production of higher value SCO barrels, an increase in contractor mining costs for increased ore volumes processed, higher commodity costs and unplanned maintenance costs.

At Fort Hills, operating costs in 2019 were higher compared to the prior year due to the ramp up of production in 2018 and an increase in planned maintenance.

Suncor's share of Syncrude operating costs were lower than the prior year, primarily due to lower unplanned maintenance costs resulting from improved reliability.

Oil Sands transportation costs in 2019 were comparable to the prior year.

DD&A expense for 2019 increased when compared to 2018 due to additional depreciation associated with the transition to IFRS 16.

Cash Operating Costs

Year ended December 31	2019	2018	2017
Oil Sands operating, selling and general expense (OS&G)	**8 027**	7 577	6 262
Oil Sands operations cash operating costs [1] reconciliation			
Oil Sands operations OS&G	**4 639**	4 222	4 067
Non-production costs [2]	**(179)**	(100)	(106)
Excess power capacity and other [3]	**(241)**	(237)	(232)
Inventory changes	**48**	(14)	1
Oil Sands operations cash operating costs [1] ($ millions)	**4 267**	3 871	3 729
Oil Sands operations cash operating costs [1] ($/bbl)	**28.20**	25.25	23.80
Fort Hills cash operating costs [1] reconciliation			
Fort Hills OS&G	**921**	832	—
Non-production costs [2]	**(115)**	(120)	—
Inventory changes	**9**	55	—
Fort Hills cash operating costs [1] ($ millions)	**815**	767	—
Fort Hills cash operating costs [1] ($/bbl)	**26.15**	31.20	—
Syncrude cash operating costs [1] reconciliation			
Syncrude OS&G	**2 467**	2 523	2 195
Non-production costs [2]	**(82)**	(33)	(37)
Syncrude cash operating costs [1] ($ millions)	**2 385**	2 490	2 158
Syncrude cash operating costs [1] ($/bbl)	**37.95**	47.25	44.05

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

(2) Significant non-production costs include, but are not limited to, share-based compensation expense and research expenses. Non-production costs at Fort Hills also include, but are not limited to, project startup costs, excess power revenue from cogeneration units and an adjustment to reflect internally produced diesel from Oil Sands operations at the cost of production.

(3) Oil Sands operations excess power capacity and other includes, but is not limited to, the operational revenue impacts of excess power from cogeneration units and the natural gas expense recorded as part of a non-monetary arrangement involving a third-party processor.

(1) Oil Sands operations cash operating costs is a non-GAAP financial measure. See the Advisories – Non-GAAP Financial Measures section of this MD&A.

Oil Sands operations cash operating costs per barrel [1] averaged $28.20 in 2019, compared to $25.25 in 2018, reflecting higher contractor mining, commodity and unplanned maintenance costs, as well as higher costs associated with the production of higher value SCO barrels. Total Oil Sands operations cash operating costs increased to $4.267 billion from $3.871 billion in the prior year.

In 2019, non-production costs, which are excluded from Oil Sands operations cash operating costs, were higher than the prior year, primarily due to an increase in research and development costs and share-based compensation expense.

Oil Sands operations inventory changes in 2019 reflect a build of higher value SCO, partially offset by a draw of bitumen inventory.

Fort Hills cash operating costs per barrel averaged $26.15 in 2019, compared to $31.20 in 2018, reflecting the impact of the production ramp up throughout 2018.

Syncrude cash operating costs per barrel decreased to $37.95 in 2019, compared to $47.25 in the previous year, due to improved upgrader reliability and decreased maintenance costs. Suncor's share of total Syncrude cash operating costs decreased to $2.385 billion from $2.490 billion in 2018. Higher non-production costs compared to the prior year is due to an increase in share-based compensation expense.

Non-Cash Asset Impairment

Due to continued volatility in the crude oil price environment and resulting declines in forecasted heavy crude oil prices, the company performed an asset impairment test on its Fort Hills cash generating unit (CGU) in the Oil Sands segment. As a result, the company recorded a non-cash impairment charge of $2.80 billion (net of taxes of $0.91 billion) on its share of the Fort Hills project using the following asset-specific assumptions:

- WCS price forecast of US$40.75/bbl in 2020, US$45.60/bbl in 2021, US$49.65/bbl in 2022, US$51.55/bbl in 2023 and US$52.90/bbl in 2024, escalating at 2% per year thereafter over the life of the project up to 2060, adjusted for asset-specific location and quality differentials;
- the company's share of production ranging from 96,000 to 106,000 bbls/d over the life of the project;
- cash operating costs averaging $22/bbl to $24/bbl over the life of the project (expressed in real dollars) reflects operating, selling and general expense

adjusted for non-production costs, including share-based compensation, research costs, and excess power revenue; and

- risk-adjusted discount rate of 7.5% (after-tax).

The recoverable amount of the Fort Hills CGU was $7.7 billion as at December 31, 2019, which also includes the cost of carbon compliance in accordance with current provincial and federal regulations which starts at $30/tonne in 2020, reaches $50/tonne by 2022 and escalates at the rate of inflation thereafter. The estimate of the recoverable amount is most sensitive to the WCS price forecast and

discount rate. A 5% decrease in price would have resulted in an increase to the impairment charge of approximately $1.2 billion (after-tax) on the company's share of the Fort Hills assets. A 1% increase in the discount rate would have resulted in an increase to the impairment charge of approximately $900 million (after-tax) on the company's share of the Fort Hills assets.

Planned Maintenance

Planned maintenance at MacKay River originally scheduled for the third quarter of 2020 has been accelerated to the first quarter of 2020 to coincide with an outage that occurred in the fourth quarter of 2019, in an effort to minimize impacts to annual production. Planned Upgrader 2 maintenance at Oil Sands operations and an annual turnaround at Syncrude are planned for the second quarter of 2020. Maintenance at Oil Sands operations Upgrader 1 is scheduled for the third quarter of 2020, extending into the fourth quarter of 2020. The anticipated impact of these maintenance events has been reflected in the company's 2020 guidance.

EXPLORATION AND PRODUCTION

2019 Highlights

- E&P funds from operations increased to $2.143 billion from $1.779 billion in 2018, and operating earnings increased to $1.141 billion, compared to $897 million in the prior year.
- Drilling activity at Hebron is ongoing with six new production wells coming online during 2019. Production at Hebron averaged 23,500 bbls/d in 2019, net to Suncor, compared to 13,000 bbls/d in 2018.
- First oil was achieved ahead of schedule at Oda, with production averaging 3,700 boe/d in 2019. In the fourth quarter of 2019, Oda averaged production of 7,800 boe/d.
- In 2019, the company sanctioned the Terra Nova ALE project, which is expected to extend the life of Terra Nova by approximately a decade and is planned for execution by the end of 2020.

Strategy and Investment Update

The E&P segment delivers geographically diversified cash flows and focuses primarily on low-cost projects that deliver significant returns, cash flow and long term-value.

The Terra Nova ALE project is scheduled to commence in the second quarter of 2020, with the vessel returning to service in the fourth quarter of 2020. Production at Terra Nova is planned to resume once the project is completed. The project is expected to extend the production life and capacity of the existing Terra Nova asset by approximately a decade. Execution of this work provides an opportunity to complete enhancements to the Floating Production, Storage and Offloading vessel to increase production capacity and efficiency to enable reliable operations over its extended life.

The company has ongoing development activities offshore the east coast of Canada and in the U.K. North Sea, intended to leverage existing facilities and infrastructure to provide incremental production and extend the productive life of existing fields. These activities are planned to continue in 2020, with development drilling at Hebron and Hibernia, the West White Rose Project, Buzzard Phase 2, and the Fenja project in Norway. The Rosebank project is currently in the pre-sanction phase with a sanction decision planned for late 2022.

Through Suncor's midstream and logistics network, the company secures market access, optimizes price realizations associated with crude oil marketing, manages inventory levels and limits the impacts of external market factors.

Financial Highlights[1]

Year ended December 31 ($ millions)	2019	2018	2017
Gross revenues[2]	**3 372**	3 474	3 177
Less: Royalties[2]	**(302)**	(257)	(266)
Operating revenues, net of royalties	**3 070**	3 217	2 911
Net earnings	**1 005**	807	721
Adjusted for:			
Asset Impairment	**393**	—	—
(Gain) on significant disposals and loss on equity investment [3]	**(187)**	90	—
Impact of income tax rate adjustments on deferred income taxes [4]	**(70)**	—	14
Operating earnings[5]	**1 141**	897	735
Funds from operations[5]	**2 143**	1 779	1 756

(1) 2018 and 2017 have been restated to reflect the change to the company's segmented presentation of its Energy Trading business, with no impact to overall consolidated results. The Energy Trading business is now included within each of the respective operating business segments to which the respective trading activity relates. Suncor's Energy Trading business was previously reported within the Corporate, Energy Trading and Eliminations segment.

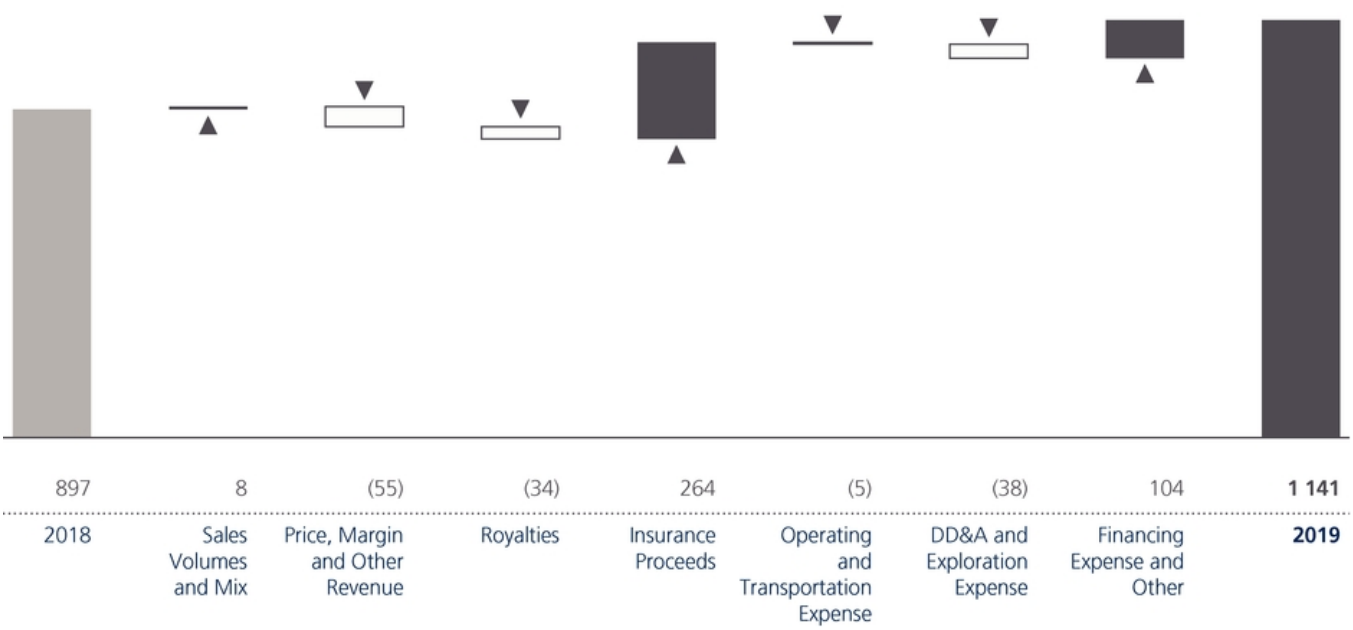
(2) Production, revenues and royalties from the company's Libya operations have been presented in the E&P section of this document on an economic basis and exclude an equal and offsetting gross up of revenues and royalties of $303 million in 2019, $395 million in 2018, and $310 million in 2017, which is required for presentation purposes in the company's financial statements under the working-interest basis.

(3) In 2018, the company recorded a net non-cash loss of $90 million, after-tax, related to an asset exchange with Canbriam.

(4) In 2017, adjustments to the company's deferred income taxes related to tax reform legislation in the U.S. for North America Onshore assets.

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

Bridge Analysis of Operating Earnings ($ millions)[1]



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

Operating earnings were $1.141 billion for E&P in 2019, compared to $897 million in the prior year, with the increase largely due to the receipt of $264 million, after-tax, for insurance proceeds related to the company's assets in Libya and prior year losses recorded on an equity investment in Canbriam, which was sold in 2019. Operating earnings were

negatively impacted by lower price realizations consistent with the decline in the Brent crude benchmark, higher DD&A and increased royalties. The insurance proceeds received may be subject to a provisional repayment that may be dependent on the future performance and cash flows from Suncor's Libyan assets.

Net earnings were $1.005 billion for the E&P segment in 2019, compared to $807 million in 2018, and were impacted by the same factors as operating earnings described above. In addition, net earnings in 2019 included an after-tax impairment charge of $393 million against the company's interest in White Rose, as discussed below, and a one-time deferred income tax recovery of $70 million associated with a staged reduction to the Alberta corporate income tax rate of 1% each year from 2019 to 2022. Net earnings in 2019 also included an after-tax gain of $139 million on the sale of the company's interest in Canbriam and an after-tax gain of $48 million related to the sale of certain non-core assets.

Funds from operations were $2.143 billion in 2019, compared to $1.779 billion in 2018. The increase was largely due to the same factors that impacted operating earnings above, adjusted for the impact of non-cash DD&A.

Production Volumes

Year ended December 31	**2019**	2018	2017
E&P Canada			
Terra Nova (mbbls/d)	**11.6**	11.7	11.5
Hibernia (mbbls/d)	**20.1**	22.1	28.5
White Rose (mbbls/d)	**4.7**	6.6	11.4
Hebron (mbbls/d)	**23.5**	13.0	0.4
North America Onshore (mboe/d)	**—**	0.5	1.9
Total E&P Canada production (mboe/d)	**59.9**	53.9	53.7
E&P International			
Buzzard (mboe/d)	**31.9**	34.2	43.8
Golden Eagle (mboe/d)	**9.0**	12.4	19.6
United Kingdom (mboe/d)	**40.9**	46.6	63.4
Norway – Oda (mboe/d)	**3.7**	—	—
Libya (mbbls/d)	**2.3**	2.9	4.5
Total E&P International production (mboe/d)	**46.9**	49.5	67.9
Total Production (mboe/d)	**106.8**	103.4	121.6
Total Sales Volumes (mboe/d)	**106.0**	102.8	120.8

E&P Canada production volumes increased to 59,900 boe/d in 2019 from 53,900 boe/d in 2018, primarily due to the ramp up of Hebron production throughout 2019 and the continued staged return of White Rose to normal operating rates, partially offset by an unplanned outage at Hibernia during the year.

E&P International production volumes averaged 46,900 boe/d in 2019, compared to 49,500 boe/d in 2018, with the increased production from Oda, which began production in 2019, more than offset by natural declines in the U.K.

Price Realizations

Year ended December 31 Net of transportation costs, but before royalties	**2019**	2018	2017
Exploration and Production			
E&P Canada – Crude oil and natural gas liquids ($/bbl)	**84.86**	87.82	69.16
E&P Canada – Natural gas ($/mcf)	**—**	1.94	1.77
E&P International ($/boe)	**81.09**	86.77	65.46
E&P average price ($/boe)	**82.92**	86.96	66.20

Average price realizations from E&P Canada and E&P International in 2019 were lower than 2018, due to the decrease in benchmark prices for Brent crude in 2019 and the timing of cargo sales.

Royalties

E&P royalties were higher in 2019 due to an increase in East Coast Canada sales volumes.

Expenses and Other Factors

Operating expenses were marginally higher in 2019, compared to 2018, primarily due to the addition of Hebron operating costs and an increase in maintenance expense.

DD&A and impairment expenses increased in 2019, compared to the prior year, primarily due to the ramp up of Hebron production volumes, partially offset by decreased production in the U.K.

Exploration expense increased in 2019, as compared to 2018, as a result of exploration charges for non-commercial drilling results off the east coast of Canada and in the U.K. North Sea.

Financing expenses and other were favourable in 2019, compared to 2018, due to prior year losses recorded on an equity investment in Canbriam, which was sold in 2019.

Non-Cash Asset Impairment

Due to an increase to forecasted capital expenditures within the White Rose CGU, the company performed an asset impairment test as at December 31, 2019. As a result, the company recorded a non-cash impairment charge of $393 million (net of taxes of $128 million) on its share of the White Rose assets using the following asset-specific assumptions:

- Brent price forecast of US$65.00/bbl in 2020, escalating at 2% per year thereafter over the life of the project up to 2036 and adjusted for asset-specific location and quality differentials;
- the company's share of production of approximately 8,700 bbls/d over the life of the project;

- the company's share of future capital expenditures of $1.4 billion including the West White Rose expansion; and
- risk-adjusted discount rate of 9.0% (after-tax).

The recoverable amount of the White Rose CGU was $360 million as at December 31, 2019, which also includes the cost of carbon compliance in accordance with current provincial and federal regulations which starts at $30/tonne in 2020, reaches $50/tonne by 2022 and escalates at the rate of inflation thereafter. The estimate of the recoverable amount is most sensitive to the Brent price forecast and discount rate. A 5% decrease in price would have resulted in an increase to the impairment charge of approximately $85 million (after-tax) on the company's share of the White Rose assets. A 1% increase in the discount rate would have resulted in an increase to the impairment charge of approximately $35 million (after-tax) on the company's share of the White Rose assets.

Planned Maintenance of Operated Assets

The Terra Nova ALE project is scheduled to commence in the second quarter of 2020, with the vessel returning to service in the fourth quarter of 2020. Production at Terra Nova is planned to resume once the project is completed. The project is expected to extend the production life and capacity of the existing Terra Nova asset. The anticipated impact of the asset being offline has been reflected in the company's 2020 guidance.

REFINING AND MARKETING

2019 Highlights

- The R&M segment delivered record funds from operations of $3.863 billion and operating earnings of $2.912 billion in 2019, compared to funds from operations of $3.798 billion and operating earnings of $3.154 billion in 2018.
- R&M delivered refinery crude throughput of 438,900 bbls/d in 2019, compared to 430,800 bbls/d in 2018, driven by strong refinery utilization in 2019. Average refinery utilization was 95% in 2019, compared with 93% in 2018.
- Refined product sales were 539,400 bbls/d, with record volumes sold in the marketing channels in 2019, including a new annual record for Canadian retail sales reflecting continued strong product demand.
- R&M continues to be a key component of the company's integrated business model, allowing Suncor to significantly shield volatility in crude differentials in the Oil Sands segment through lower refinery feedstock costs. In 2019, approximately 56% of the company's crude feedstock processed at the company's refineries was internally produced SCO and diluted bitumen.
- In 2019, Suncor also completed an electric vehicle fast-charging network across Canada, demonstrating the company's continued commitment to projects that are sustainability minded and technologically advanced.

Strategy and Investment Update

The R&M network serves to maximize Suncor's integrated returns by extending the value chain from oil sands production to the end customer and is a key component of Suncor's integrated business model. The company aims to operate its refineries at optimal levels of utilization to provide reliable offtake and secure pricing for a portion of the production from the Oil Sands segment.

In 2019, Suncor continued to leverage its strong Petro-Canada™ brand through a nationwide campaign to increase sales volumes and non-petroleum revenues through the company's network of convenience stores and car washes and will continue these efforts in 2020.

Through Suncor's midstream and logistics network, the company secures market access, optimizes price realizations associated with refined products and crude oil supply, manages inventory levels and limits the impacts of external market factors.

Financial Highlights[1]

Year ended December 31 ($ millions)	2019	2018	2017
Operating revenues	**22 304**	23 778	19 755
Net earnings	**3 000**	3 154	2 622
Adjusted for:			
Impact of income tax rate adjustments on deferred taxes[2]	**(88)**	—	(140)
Gain on significant disposal[3]	**—**	—	(354)
Operating earnings[4]	**2 912**	3 154	2 128
Funds from operations[4]	**3 863**	3 798	2 823

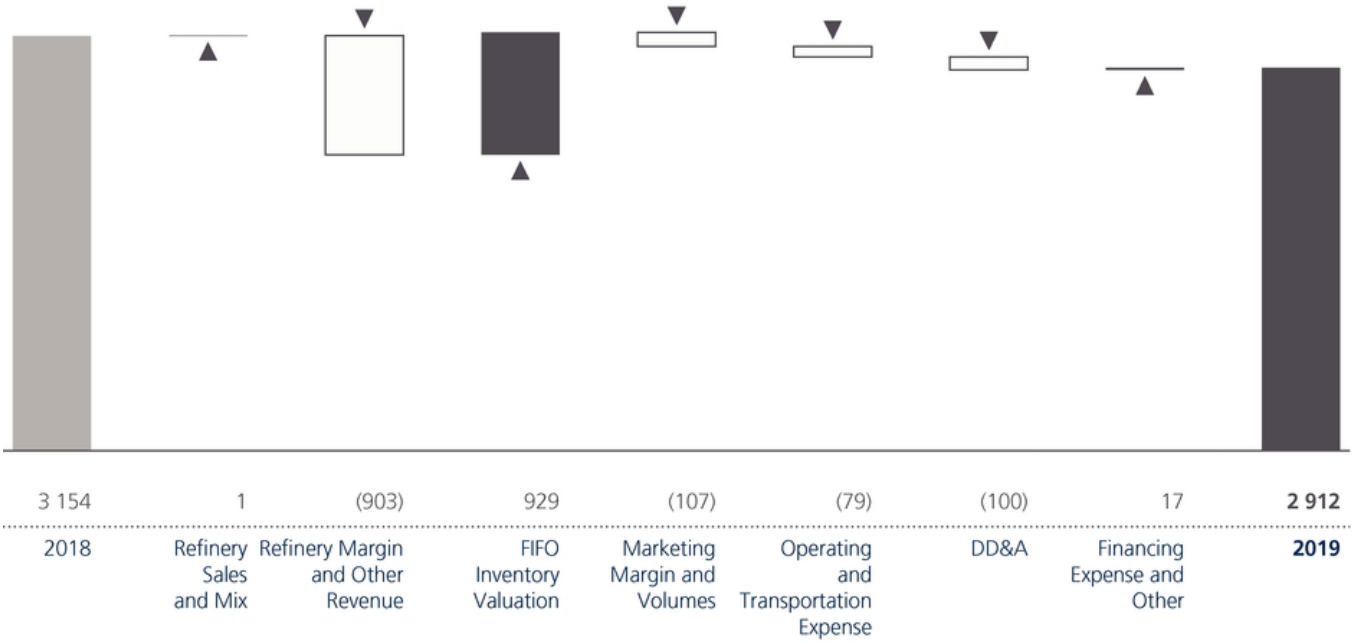
(1) 2018 and 2017 have been restated to reflect the change to the company's segmented presentation of its Energy Trading business, with no impact to overall consolidated results. The Energy Trading business is now included within each of the respective operating business segments to which the respective trading activity relates. Suncor's Energy Trading business was previously reported within the Corporate, Energy Trading and Eliminations segment.

(2) In 2017, the company recorded an adjustment to its deferred income taxes related to tax reform legislation in the U.S., with the most significant impact resulting from a decrease in the corporate tax rate from 35% to 21%.

(3) After-tax gain related to the sale of the company's lubricants business.

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

Bridge Analysis of Operating Earnings ($ millions)[1]



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

R&M contributed annual operating earnings of $2.912 billion in 2019, compared with $3.154 billion in 2018. The decrease was attributable to lower refining margins attributed primarily to significantly narrower crude differentials, lower marketing margins, and higher DD&A, partially offset by a FIFO gain in 2019 compared to a FIFO loss in the prior year associated with the significant decline in crude and refined product benchmarks near the end of 2018.

Net earnings in 2019 were $3.000 billion, compared to net earnings of $3.154 billion in 2018, and were impacted by the same factors as operating earnings described above. 2019 net earnings also included a one-time deferred income tax recovery of $88 million associated with a staged reduction to the Alberta corporate income tax rate of 1% each year from 2019 to 2022.

R&M achieved an annual funds from operations record of $3.863 billion in 2019, compared to $3.798 billion in 2018, due primarily to the same factors that impacted operating earnings described above, excluding the impacts of non-cash DD&A.

Volumes

Year ended December 31	2019	2018	2017
Crude oil processed (mbbls/d)			
Eastern North America	**203.3**	208.1	206.4
Western North America	**235.6**	222.7	234.8
Total	**438.9**	430.8	441.2
Refinery utilization[1][2] (%)			
Eastern North America	**92**	94	93
Western North America	**98**	93	98
Total	**95**	93	96
Refined Product Sales (mbbls/d)			
Gasoline	**246.6**	245.6	242.9
Distillate	**218.1**	203.4	199.3
Other	**74.7**	78.4	88.3
Total	**539.4**	527.4	530.5
Refining margin[2] ($/bbl)	**33.15**	34.50	24.20
Refining operating expense[2] ($/bbl)	**5.35**	5.35	5.05

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

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

Refinery utilization averaged 95% in 2019, compared with 93% in 2018. The increase in utilization was primarily due to a decrease in planned maintenance in 2019 compared to 2018, with the Edmonton refinery undergoing its first full plant turnaround in its history in 2018.

Total refined products sales were 539,400 bbls/d in 2019, compared to 527,400 bbls/d in 2018, with record volumes sold in the marketing channels in 2019, including a new annual record for Canadian retail sales reflecting continued strong product demand.

Prices and Margins

Refining and Product Supply prices and margins, including FIFO inventory valuation, were slightly higher in 2019 compared to 2018, and were impacted primarily by the following factors:

- An overall less favourable business environment, driven by narrower crude differentials.
- In 2019, the impact of FIFO inventory accounting, as used by the company, relative to an estimated LIFO [1] basis of accounting, had a positive impact on refining margins and net income of approximately $461 million after-tax, compared to a negative impact of $468 million after-tax in 2018, for a favourable year-over-year impact of $929 million.

Marketing gross margins in 2019 were lower than in the prior year, primarily due to finished product market conditions.

Expenses and Other Factors

Operating and transportation expenses were higher in 2019 compared to 2018, primarily due to an increase in business development costs and share-based compensation expense.

DD&A increased in 2019 compared to the prior year due to the implementation of IFRS 16.

Planned Maintenance

The company has a number of planned maintenance events, including a two-week planned maintenance event at the Commerce City refinery in the first quarter of 2020, a two-week turnaround at the Sarnia refinery scheduled in the second quarter of 2020, a four-week turnaround at the Edmonton refinery scheduled in the third quarter of 2020, and a six-week turnaround at the Montreal refinery in the third quarter and fourth quarter of 2020. The estimated impact of these maintenance events has been reflected in the company's 2020 guidance.

(1) The LIFO inventory valuation methodology is a non-GAAP financial measure. See the Advisories – Non-GAAP Financial Measures section of this MD&A.

CORPORATE AND ELIMINATIONS

2019 Highlights

- A total of $2.614 billion in dividends were paid in 2019, an increase of 17% per common share over the prior year, making 2019 the 17th consecutive year

of annual dividend increases for Suncor.

- The company repurchased 55.3 million of its own common shares for cancellation during 2019, representing 3.6% of the total outstanding common shares, for $2.274 billion, and reduced debt by $425 million, reflecting continued flexibility in the company's capital allocation strategy.
- Suncor sanctioned the Forty Mile Wind Power Project, which is expected to drive value through sustainable low-carbon power generation and the retention of generated carbon credits for utilization in Suncor's upstream business.
- In 2019, the company increased its investments in clean technology, including an aggregate of $73 million in equity investments in Enerkem Inc., a waste-to biofuels and chemicals producer.
- Subsequent to the end of the year, Suncor's Board of Directors approved an 11% increase in the quarterly dividend and a renewal of the share repurchase program. This increases the quarterly dividend from $0.420 to $0.465 per common share and provides approval for up to $2.0 billion in share repurchases beginning March 1, 2020.

Strategy and Investment Update

Returning value to shareholders continues to be a top priority for Suncor, as demonstrated by the company's history of dividend increases and commitment to its share repurchase program. Since the start of 2017, the company has completed $12.4 billion in share repurchases as of February 25, 2020, which is approximately 21% of the total outstanding common shares of the company. In 2020, the Board of Directors has approved up to a further $2.0 billion in share repurchases, reinforcing the company's ability to generate cash flow and its commitment to return cash to shareholders.

Investment in wind power and being a part of the emerging biofuel industry is a key component of Suncor's climate change action plan. In 2019, Suncor sanctioned the Forty Mile Wind Power Project in southern Alberta. This 200 MW renewable power project has an estimated total capital spend of $300 million, with 25% of the capital spent in 2019 and the remainder to be spent over the next two years. This investment approach in renewable energy is expected to generate significant value through sustainable power generation and retention of the generated carbon credits for utilization in Suncor's upstream business. This project enables Suncor to make meaningful progress towards its sustainability goal of a 30% GHG emissions intensity reduction by 2030.

In 2020, the company expects to continue to accelerate its digital transformation and implement new digital technologies across the enterprise to help improve the safety, productivity, reliability and environmental performance of our operations. As part of its digital transformation, Suncor has entered into a strategic alliance with Microsoft. This alliance enables Suncor to utilize Microsoft's full range of cloud solutions to empower a connected and collaborative workforce, build an agile data platform to increase analytics capabilities, and partner with experts while gaining access to leading edge technologies.

Financial Highlights[1]

Year ended December 31 ($ millions)	**2019**	2018	2017
Net (loss) earnings	**(679)**	(1 613)	121
Adjusted for:			
Unrealized foreign exchange (gain) loss on U.S. dollar denominated debt	**(590)**	989	(702)
Loss on interest rate swaps[2]	**—**	—	20
Non-cash loss on early payment of long-term debt[3]	**—**	—	28
Gain on significant disposal[4]	**—**	—	(83)
Impact of income tax rate adjustments on deferred income taxes[5]	**(48)**	—	2
Operating loss[6]	**(1 317)**	(624)	(614)
Corporate and Renewables	***(1 113)***	*(876)*	*(532)*
Eliminations – Intersegment profit (eliminated) realized	***(204)***	*252*	*(82)*
Funds used in operations[6]	**(1 249)**	(369)	(174)

(1) 2018 and 2017 have been restated to reflect the change to the company's segmented presentation of its Energy Trading business, with no impact to overall consolidated results. The Energy Trading business is now included within each of the respective operating business segments to which the respective trading activity relates. Suncor's Energy Trading business was previously reported within the Corporate, Energy Trading and Eliminations segment.

(2) In 2017, the company recognized an after-tax loss on forward interest rate swaps of $20 million due to changes in long-term interest rates.

(3) In 2017, the company redeemed US$1.250 billion, US$600 million and $700 million of higher interest long-term debt that was originally due in 2018, reducing future financing charges for a net economic benefit. As a result of early redemption, the company incurred an after-tax charge of $28 million, net of associated realized foreign currency hedges.

(4) In 2017, the company recorded an after-tax gain of $83 million related to the sale of its interest in the Cedar Point wind facility.

(5) In 2017, the company recorded an adjustment to its deferred income taxes related to the tax reform legislation in the U.S., with the most significant impact resulting from a decrease in the corporate tax rate from 35% to 21%.

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

Corporate and Renewables

Corporate incurred an operating loss of $1.113 billion in 2019, compared with an operating loss of $876 million in 2018, reflecting lower operational foreign exchange gains in 2019 in comparison to the prior year, an increase in share-based compensation expense, higher interest expenses and lower capitalized interest. Suncor capitalized $122 million of its borrowing costs in 2019 as part of the cost of major development assets and construction projects in progress, compared to $156 million in the prior year, with the decrease resulting from the staged commissioning of Fort Hills in 2018.

Year ended December 31	**2019**	2018	2017
Renewable Energy power generation marketed (gigawatt hours) [(1)]	**184**	183	255

(1) Power generated includes curtailed production for which the company was compensated.

Eliminations – Intersegment profit (eliminated) realized

Eliminations reflect the deferral or realization of profit on crude oil sales from Oil Sands to R&M. Consolidated profits are only realized when the refined products produced from internal purchases of crude feedstock have been sold to third parties. In 2019, the company eliminated $204 million of after-tax intersegment profit, compared to a realization of profit of $252 million in the prior year. The change year-over-year was primarily due to the increase in Oil Sands crude margins in 2019, as lower margin crude feedstock inventory sourced internally from Oil Sands was sold and replaced by higher margin crude feedstock inventory, resulting in an elimination of profit at the enterprise level.

The net loss for Corporate and Eliminations was $679 million in 2019, compared to a net loss of $1.613 billion in 2018. In addition to the factors impacting operating earnings discussed above, the net loss in 2019 included a $590 million unrealized after-tax foreign exchange gain on the revaluation of U.S. dollar denominated debt and a $48 million deferred income tax recovery associated with the Government of Alberta's staged reduction of the corporate income tax rate from 12% to 8% over the next four years. The net loss in the prior year included a $989 million unrealized after-tax foreign exchange loss on the revaluation of U.S. dollar denominated debt.

Funds used in operations for the Corporate and Eliminations segment were $1.249 billion in 2019, compared to $369 million in 2018, and were influenced by the same factors that impacted operating earnings, adjusted for the non-cash component of share-based compensation expense.

5. FOURTH QUARTER 2019 ANALYSIS

Financial and Operational Highlights[1]

Three months ended December 31 ($ millions, except as noted)	2019	2018
Net (loss) earnings		
Oil Sands	**(2 682)**	(377)
Exploration and Production	**(162)**	(115)
Refining and Marketing	**558**	762
Corporate and Eliminations	**(49)**	(550)
Total	**(2 335)**	(280)
Operating earnings (loss)[2]		
Oil Sands	**277**	(377)
Exploration and Production	**231**	108
Refining and Marketing	**558**	762
Corporate and Eliminations	**(284)**	87
Total	**782**	580
Funds from (used in) operations[2]		
Oil Sands	**1 405**	607
Exploration and Production	**555**	331
Refining and Marketing	**793**	873
Corporate and Eliminations	**(200)**	196
Total funds from operations	**2 553**	2 007
Changes in non-cash working capital	**(249)**	1 033
Cash flow provided by operating activities	**2 304**	3 040
Production volumes (mboe/d)		
Oil Sands	**662.3**	740.8
Exploration and Production	**115.9**	90.2
Total	**778.2**	831.0

(1) 2018 has been restated to reflect the change to the company's segmented presentation of its Energy Trading business, with no impact to overall consolidated results. The Energy Trading business is now included within each of the respective operating business segments to which the respective trading activity relates. Suncor's Energy Trading business was previously reported within the Corporate, Energy Trading and Eliminations segment.

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

Net Loss

Suncor had a consolidated net loss for the fourth quarter of 2019 of $2.335 billion, compared to a net loss of $280 million for the prior year quarter. The net loss was affected by the same factors that influenced operating earnings described subsequently in this section of this document. Other items affecting net losses over these periods included:

- During the fourth quarter of 2019, the company recorded after-tax non-cash impairment charges of $2.803 billion on its share of the Fort Hills assets, in the Oil Sands segment, due to a decline in forecasted heavy crude oil prices and $393 million against its interest in White Rose, in the E&P segment, due to increased capital cost estimates at the West White Rose Project.
- The after-tax unrealized foreign exchange gain on the revaluation of U.S. dollar denominated debt was $235 million for the fourth quarter of 2019, compared to a loss of $637 million for the fourth quarter of 2018.
- The fourth quarter of 2018 included a $223 million after-tax impairment charge in the E&P segment associated with the company's equity investment in Canbriam. This included the reversal of a $133 million after-tax gain recorded in the first quarter of 2018, when the equity investment was acquired through an asset exchange, for a net after-tax impairment of $90 million in 2018.

Cash Flow provided by Operating Activities and Funds from Operations

Funds from operations were $2.553 billion in the fourth quarter of 2019, compared to $2.007 billion in the fourth quarter of 2018, and were influenced by the same

factors impacting operating earnings described in the Segmented Analysis below, excluding the impact of DD&A and share-based compensation expenses.

Cash flow provided by operating activities, which includes changes in non-cash working capital, was $2.304 billion in the fourth quarter of 2019, compared to $3.040 billion in the fourth quarter of 2018, and was influenced by the same factors impacting operating earnings noted below, excluding the impact of DD&A and share-based compensation expenses. In addition, cash flow provided by operating activities was impacted by a use of cash from working capital in 2019 as compared to a source of cash in 2018, which was due to a decrease in accounts receivable balances and refinery inventory value associated with lower year end benchmark prices.

Segmented Analysis

Oil Sands

The Oil Sands segment had operating earnings of $277 million in the fourth quarter of 2019, compared to an operating loss of $377 million in the prior year quarter. The improved results were primarily due to higher realized crude prices due to improved western Canadian crude oil differentials, including a substantial narrowing of heavy crude and SCO differentials, more than offsetting benchmark pricing declines. This was partially offset by lower overall production volumes due to planned maintenance and mandatory production curtailments and higher DD&A.

Oil Sands operations production was 418,100 bbls/d in the fourth quarter of 2019, compared to 432,700 bbls/d in the prior year quarter. The decrease in production was primarily due to maintenance, including planned annual coker maintenance at Oil Sands Base, increased yield loss associated with higher SCO production, mandatory production curtailments and an outage at MacKay River, which is expected to return to operation early in the second quarter of 2020. Upgrader utilization was 86% in the fourth quarter of 2019, compared to 79% in the prior year period.

Fort Hills production averaged 87,900 bbls/d in the fourth quarter of 2019, compared to 98,500 bbls/d in the prior year quarter. The decrease in production was due to planned maintenance, which was completed during the quarter, and mandatory production curtailments. Fort Hills remains adversely impacted by mandatory production curtailments due to the continued, disproportionate effect of curtailment as it is applied on a 2018 production basis when the asset was ramping up to full production rates. However, the company was able to partially mitigate production impacts by internally transferring credits from Oil Sands operations and purchasing third-party credits.

Suncor's share of Syncrude production and sales was 156,300 bbls/d in the fourth quarter of 2019, compared to 209,600 bbls/d in the prior year quarter. The decrease in production was primarily due to planned maintenance that commenced in the third quarter of 2019 and was completed in the fourth quarter, compared to no planned maintenance in the prior year quarter, and mandatory production curtailments. Upon completion of maintenance, Syncrude was able to partially mitigate the impacts of curtailment on production by purchasing curtailment credits from partners and third parties.

Sales volumes for Oil Sands operations were 417,600 bbls/d in the fourth quarter of 2019, compared to 460,500 bbls/d in the prior year quarter, and were influenced by the same factors influencing production, combined with a draw in inventory in the prior year quarter.

Exploration and Production

Operating earnings for the E&P segment were $231 million in the fourth quarter of 2019, compared to $108 million in the prior year quarter, primarily as a result of higher East Coast Canada production volumes and crude price realizations, partially offset by higher royalties and DD&A related to the increased production. Financing and other expenses in the fourth quarter of 2019 were lower when compared to the fourth quarter of 2018, as the prior year quarter had equity losses related to an investment in Canbriam that the company subsequently sold.

Production volumes for E&P Canada were 69,600 boe/d in the fourth quarter of 2019, compared to 47,900 boe/d in the prior year quarter. The increase in production was primarily due to the ramp up of Hebron production throughout 2019 and the impact of a temporary production interruption due to a major storm system that impacted all E&P East Coast Canada assets in the prior year quarter.

E&P International production increased to 46,300 boe/d in the fourth quarter of 2019, from 42,300 boe/d in the prior year quarter, primarily due to increased production from Oda, which began production near the end of the first quarter of 2019, partially offset by natural declines in the U.K.

Refining and Marketing

R&M operating earnings in the fourth quarter of 2019 were $558 million, compared to $762 million in the prior year quarter. The decrease in operating earnings was primarily due to lower refining margins, attributed to significantly narrower crude differentials, lower refinery crude throughput, and lower marketing margins, partially offset by a lower FIFO loss, as the prior year quarter included a significant FIFO loss associated with the decline in crude and refined product benchmarks.

Refinery crude throughput was 447,500 bbls/d in the fourth quarter of 2019, compared to 467,900 bbls/d in the prior year quarter. Both periods achieved high utilization rates at 97% and 101%, respectively.

Refined product sales increased in the fourth quarter of 2019 to 534,600 bbls/d, compared to 530,600 bbls/d in the prior year quarter, reflecting strong retail sales volumes.

Corporate and Eliminations

Corporate and Eliminations had an operating loss of $284 million in the fourth quarter of 2019, compared to operating earnings of $87 million in the fourth quarter of 2018. During the fourth quarter of 2019, the company realized $11 million of after-tax intersegment profit, compared to a realization of $265 million of after-tax intersegment profit in the prior year quarter. The realization of deferred profit in the fourth quarter of 2019 was driven by the decrease in Oil Sands price realizations over the quarter, as higher margin crude refinery feedstock inventory sourced internally from Oil Sands was sold and replaced by lower margin crude feedstock inventory. The realization of deferred profit in the prior year quarter was driven by the decrease in oil sand benchmark prices, as a result of the significant widening of crude differentials.

The increased loss was also attributable to a share-based compensation expense incurred in the fourth quarter of 2019, as compared to a share-based compensation recovery in the prior year quarter, and a lower operational foreign exchange gain than in the prior year quarter. Suncor capitalized $37 million of its borrowing costs in the fourth quarter of 2019 as part of the cost of major development assets and construction projects in progress, compared to $28 million in the prior year quarter.

6. QUARTERLY FINANCIAL DATA

Financial Summary

Three months ended ($ millions, unless otherwise noted)	**Dec 31 2019**	Sept 30 2019	June 30, 2019	Mar 31 2019	Dec 31 2018	Sept 30 2018	June 30, 2018	Mar 31 2018
Total production (mboe/d)								
Oil Sands	**662.3**	670.0	692.2	657.2	740.8	651.7	547.6	571.7
Exploration and Production	**115.9**	92.3	111.7	107.1	90.2	92.1	114.1	117.7
	778.2	762.3	803.9	764.3	831.0	743.8	661.7	689.4
Revenues and other income								
Operating revenues, net of royalties	**9 487**	9 803	10 071	8 983	8 561	10 847	10 327	8 807
Other income (loss)	**111**	93	27	414	384	16	101	(57)
	9 598	9 896	10 098	9 397	8 945	10 863	10 428	8 750
Net (loss) earnings	**(2 335)**	1 035	2 729	1 470	(280)	1 812	972	789
per common share – basic (dollars)	**(1.52)**	0.67	1.74	0.93	(0.18)	1.12	0.60	0.48
per common share – diluted (dollars)	**(1.52)**	0.67	1.74	0.93	(0.18)	1.11	0.59	0.48
Operating earnings[1]	**782**	1 114	1 253	1 209	580	1 557	1 190	985
per common share – basic[1] (dollars)	**0.51**	0.72	0.80	0.77	0.36	0.96	0.73	0.60
Funds from operations[1]	**2 553**	2 675	3 005	2 585	2 007	3 139	2 862	2 164
per common share – basic[1] (dollars)	**1.66**	1.72	1.92	1.64	1.26	1.94	1.75	1.32
Cash flow provided by operating activities	**2 304**	3 136	3 433	1 548	3 040	4 370	2 446	724
per common share – basic (dollars)	**1.50**	2.02	2.19	0.98	1.90	2.70	1.50	0.44
ROCE[1] (%) for the twelve months ended	**4.9**	9.7	10.4	8.2	8.0	9.7	8.3	6.5
ROCE[1][2] (%) excluding major projects in progress for the twelve months ended	**5.1**	9.9	10.6	8.3	8.2	10.4	9.5	7.8
After-tax unrealized foreign exchange gain (loss) on U.S. dollar denominated debt	**235**	(127)	221	261	(637)	195	(218)	(329)
Common share information (dollars)								
Dividend per common share	**0.42**	0.42	0.42	0.42	0.36	0.36	0.36	0.36
Share price at the end of trading								
Toronto Stock Exchange (Cdn$)	**42.56**	41.79	40.85	43.31	38.13	49.98	53.50	44.49
New York Stock Exchange (US$)	**32.80**	31.58	31.16	32.43	27.97	38.69	40.68	34.54

(1) Non-GAAP financial measures. See the Advisories – Non-GAAP Financial Measures section of this MD&A. ROCE excludes capitalized costs related to major projects in progress. Operating earnings (loss) for each quarter are defined in the Non-GAAP Financial Measures Advisory section and reconciled to GAAP measures in the Consolidated Financial Information and Segment Results and Analysis sections of each quarterly Report to Shareholders issued by Suncor (Quarterly Reports) in respect of the relevant quarter. Funds from operations and ROCE for each quarter are defined and reconciled to GAAP measures in the Non-GAAP Financial Measures Advisory section of each Quarterly Report issued by Suncor in respect of the relevant quarter.

(2) ROCE excluding major projects in progress would have been 8.7%, 8.0%, and 8.6% for the second quarter of 2019, third quarter of 2019, and fourth quarter of 2019, respectively, excluding the impacts of impairments of $3.352 billion in the fourth quarter of 2019 and the impact of the $1.116 billion deferred tax recovery for the Alberta corporate income tax rate change in the second quarter of 2019.

Business Environment

Three months ended (average for the period ended, except as noted)		Dec 31 2019	Sept 30 2019	June 30 2019	Mar 31 2019	Dec 31 2018	Sept 30 2018	June 30 2018	Mar 31 2018
WTI crude oil at Cushing	US$/bbl	**56.95**	56.45	59.85	54.90	58.85	69.50	67.90	62.90
Dated Brent crude	US$/bbl	**63.30**	61.90	68.85	63.20	67.80	75.25	74.40	66.80
Dated Brent/Maya FOB price differential	US$/bbl	**9.30**	5.20	6.90	5.00	4.35	10.20	12.40	7.70
MSW at Edmonton	Cdn$/bbl	**68.10**	68.35	73.40	66.45	42.70	82.10	80.95	72.45
WCS at Hardisty	US$/bbl	**41.10**	44.20	49.20	42.50	19.50	47.35	48.65	38.60
Light/heavy crude oil differential for WTI at Cushing less WCS at Hardisty	US$/bbl	**(15.85)**	(12.25)	(10.65)	(12.40)	(39.35)	(22.15)	(19.25)	(24.30)
SYN-WTI (differential) premium	US$/bbl	**(0.70)**	0.40	0.15	(2.30)	(21.60)	(0.90)	(0.65)	(1.45)
Condensate at Edmonton	US$/bbl	**53.00**	52.00	55.90	50.55	45.30	66.80	68.50	63.15
Natural gas (Alberta spot) at AECO	Cdn$/mcf	**2.50**	0.95	1.05	2.55	1.60	1.20	1.20	1.75
Alberta Power Pool Price	Cdn$/MWh	**46.95**	46.85	56.35	70.75	55.55	54.45	56.00	34.95
New York Harbor 2-1-1 crack (1)	US$/bbl	**18.50**	19.75	22.40	19.10	18.75	19.50	21.45	17.95
Chicago 2-1-1 crack (1)	US$/bbl	**14.45**	17.05	21.55	15.30	16.25	19.90	19.10	14.30
Portland 2-1-1 crack (1)	US$/bbl	**25.75**	23.85	29.15	19.35	24.25	22.05	28.75	21.05
Gulf Coast 2-1-1 crack (1)	US$/bbl	**17.10**	20.00	21.70	17.85	17.45	19.30	20.50	16.35
Exchange rate	US$/Cdn$	**0.76**	0.76	0.75	0.75	0.76	0.77	0.77	0.79
Exchange rate (end of period)	US$/Cdn$	**0.77**	0.76	0.76	0.75	0.73	0.77	0.76	0.78

(1) 2-1-1 crack spreads are indicators of the refining margin generated by converting two barrels of WTI into one barrel of gasoline and one barrel of diesel. The company previously quoted 3-2-1 crack margin benchmarks based on wider use and familiarity with these benchmarks and, although the 3-2-1 crack spread is more commonly quoted, the company's refinery production is better aligned with a 2-1-1 crack spread, which better reflects the approximate composition of Suncor's overall refined product mix. The crack spreads presented here generally approximate the regions into which the company sells refined products through retail and wholesale channels.

Significant or Unusual Items Impacting Net Earnings

Trends in Suncor's quarterly net earnings and cash flow provided by operating activities are driven primarily by production volumes, which can be significantly impacted by factors such as mandatory production curtailments in the province of Alberta, which began on January 1, 2019 and was in effect for the duration of 2019.

Trends in Suncor's quarterly net earnings and cash flow provided by operating activities are also affected by changes in commodity prices, price differentials, refining crack spreads and foreign exchange rates, as described in the Financial Information section of this MD&A. In addition to the impacts of changes in production volumes and business environment, net earnings over the last eight quarters were affected by the following events or significant adjustments:

- During the fourth quarter of 2019, the company recorded after-tax non-cash impairment charges of $2.803 billion on its share of the Fort Hills assets, in the Oil Sands segment, due to a decline in forecasted heavy crude oil prices and $393 million against its interest in White Rose, in the E&P segment, due to increased capital cost estimates at the West White Rose Project.
- The third quarter of 2019 included an after-tax gain of $48 million in the E&P segment related to the sale of certain non-core assets.
- In the second quarter of 2019, the company recorded a $1.116 billion deferred income tax recovery associated with the Government of Alberta's substantive enactment of legislation for the staged reduction of the corporate income tax rate from 12% to 8% over the next four years.
- In the second quarter of 2019, Suncor sold its 37% interest in Canbriam for total proceeds and an equivalent gain of $151 million ($139 million after-tax), which had previously been written down to nil in the fourth quarter of 2018 following the company's assessment of forward natural gas prices and the impact on estimated future cash flows.
- The fourth quarter of 2018 included a $223 million after-tax impairment charge in the E&P segment associated with the company's equity investment in Canbriam. This included the reversal of a $133 million after-tax gain recorded in the first quarter of 2018, when the equity investment was acquired through an asset exchange, for a net after-tax impairment of $90 million in 2018.
- The third quarter of 2018 included an after-tax gain of $60 million in the Oil Sands segment relating to the sale of the company's interest in the Joslyn oil sands mining project.

7. CAPITAL INVESTMENT UPDATE

Capital and Exploration Expenditures by Segment

Year ended December 31 ($ millions)	**2019**	2018	2017
Oil Sands	**3 522**	3 546	5 059
Exploration and Production	**1 070**	946	824
Refining and Marketing	**818**	856	634
Corporate and Eliminations	**148**	58	34
Total	**5 558**	5 406	6 551
Less: capitalized interest on debt	**(122)**	(156)	(729)
	5 436	5 250	5 822

Capital and Exploration Expenditures by Type, excluding capitalized interest [(1)]

Year ended December 31, 2019 ($ millions)	Asset Sustainment and Maintenance[(2)]	Economic Investment[(3)]	**Total**
Oil Sands			
Oil Sands Base	*1 667*	*164*	***1 831***
In Situ	*113*	*575*	***688***
Fort Hills	*331*	*72*	***403***
Syncrude	*493*	*46*	***539***
Exploration and Production	5	1 011	**1 016**
Refining and Marketing	566	245	**811**
Corporate and Eliminations	52	96	**148**
	3 227	2 209	**5 436**

(1) The classification of the company's capital expenditures has been updated to "asset sustainment and maintenance" and "economic investment" to better reflect the types of capital investments being made by the company.

(2) Asset sustainment and maintenance capital expenditures include capital investments that deliver on existing value by ensuring compliance or maintaining relations with regulators and other stakeholders, maintaining current processing capacity, and delivering existing developed reserves.

(3) Economic investment capital expenditures include capital investments that result in an increase in value through adding reserves, improving processing capacity, utilization, cost or margin, including associated infrastructure.

In 2019, Suncor's capital expenditures on property, plant and equipment and exploration activities totalled $5.436 billion, excluding capitalized borrowing costs of $122 million. Activity in 2019 included the following:

Oil Sands Base

Oil Sands Base asset sustainment and maintenance capital expenditures were $1.667 billion in 2019 and were primarily focused on ensuring continued safe, reliable and efficient operations, as well as environmental compliance, such as the continued development of tailings infrastructure. The company's planned maintenance program in 2019 included planned maintenance at Upgrader 1 in the spring and major maintenance at Upgrader 2 in the fall, the continued development of tailings infrastructure in addition to other reliability and sustainment projects across the operation.

Oil Sands Base economic capital of $164 million in 2019 was focused on projects expected to improve productive capacity. This also included the company's investment to progress low-carbon power generation by replacing its coke-fired boilers with a new cogeneration facility and the construction of interconnecting pipelines between Suncor's Oil Sands Base and Syncrude.

In Situ

In Situ capital expenditures were $688 million, of which $575 million was directed towards economic investment activities, which focused on the ongoing design and construction of well pads to develop additional reserves that are expected to maintain existing production levels at Firebag and MacKay River in future years as production from existing well pads declines.

Fort Hills

Fort Hills capital expenditures were $403 million in 2019, with $72 million directed towards economic investment spending.

Asset sustainment and maintenance capital expenditures of $331 million included mine and tailings development to support ongoing operations.

Syncrude

Syncrude capital expenditures were $539 million in 2019, the majority of which was for asset sustainment and maintenance capital expenditures focused on improving asset reliability and included capital related to turnarounds and maintenance.

Exploration and Production

E&P capital and exploration expenditures were $1.016 billion in 2019, and were primarily focused on economic investment projects, including development drilling at Hibernia, Hebron and Buzzard, and development work on Terra Nova, Fenja and the West White Rose projects.

Refining and Marketing

R&M capital expenditures were $811 million in 2019, and were primarily related to the ongoing sustainment of and enhancement to refinery and retail operations, and other economic investment projects on logistics and the company's retail and wholesale network, including an electric vehicle fast-charging network.

Corporate

Corporate capital expenditures were $148 million, primarily directed towards the company's information technology initiatives and the Forty Mile Wind Power Project.

Suncor anticipates 2020 capital expenditures to be directed to the following projects and initiatives:

Oil Sands Operations

For 2020, plans for economic investment will include capital to progress low-carbon power generation to replace the coke-fired boilers and continued construction of the interconnecting pipelines between Suncor's Oil Sands Base Plant and Syncrude. Additional investment to maintain production capacity at existing facilities includes continued development of new reserves by building new well pads at In Situ and improving mining efficiency through the continued implementation of AHS.

Asset sustainment and maintenance capital will focus on tailings management and planned maintenance at Upgraders 1 and 2.

Fort Hills

Asset sustainment and maintenance capital expenditures for 2020 will focus on ongoing development of mining and tailings management projects to preserve production capacity. In addition, Fort Hills continues to invest in improving mining efficiency through the implementation of AHS.

Syncrude

For 2020, plans for economic investment will include capital to progress the Mildred Lake Extension-West Mine and continued construction of the interconnecting pipelines between Suncor's Oil Sands Base and Syncrude, which are expected to enhance integration between the assets and increase reliability at Syncrude.

Sustaining capital expenditures for 2020 will focus on planned maintenance and reliability programs aimed at maintaining production capacity.

Exploration and Production

Capital expenditures for 2020 are expected to include economic investments at West White Rose Project, Hibernia, Buzzard, and Hebron, as well as the Norwegian Fenja project.

In 2019, the company sanctioned the Terra Nova ALE project, which is expected to extend the life of Terra Nova by approximately a decade and is planned for execution in 2020.

Refining and Marketing

The company expects that sustaining capital will focus on ongoing sustainment and enhancement to refinery and retail operations, and other economic investment projects on logistics and the company's retail and wholesale network.

Corporate

For 2020, the company plans to make economic investments in digital technology initiatives and the Forty Mile Wind Power Project in southern Alberta, which was sanctioned in 2019.

8. FINANCIAL CONDITION AND LIQUIDITY

Liquidity and Capital Resources

At December 31 ($ millions, except as noted)	2019	2018	2017
Cash flow provided by (used in)			
Operating activities	**10 421**	10 580	8 966
Investing activities	**(5 088)**	(6 697)	(5 019)
Financing activities	**(5 537)**	(4 426)	(4 223)
Foreign exchange (loss) gain on cash and cash equivalents	**(57)**	92	(68)
Decrease in cash and cash equivalents	**(261)**	(451)	(344)
Cash and cash equivalents, end of year	**1 960**	2 221	2 672
Return on Capital Employed (%)[1]			
Excluding major projects in progress[2][3]	**5.1**	8.2	8.6
Including major projects in progress[2]	**4.9**	8.0	6.7
Net debt to funds from operations[1][4][5] (times)	**1.5**	1.5	1.4
Interest coverage on long-term debt (times)			
Earnings basis[6]	**3.4**	6.4	6.5
Funds from operations basis[1][5][7]	**13.4**	14.1	11.2

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

(2) 2019 ROCE includes asset impairment charges of $3.352 billion after-tax.

(3) Excludes capitalized costs related to major projects in progress. ROCE excluding major projects in progress would have been 8.6% in 2019, excluding the impacts of impairments of $3.352 billion and the impact of the $1.116 billion deferred tax recovery relating to a change in the Alberta corporate income tax rate.

(4) Net debt is equal to total debt less cash and cash equivalents.

(5) Funds from operations and metrics that use funds from operations are non-GAAP financial measures. See the Non-GAAP Financial Measures Advisory section of this document.

(6) Equal to net earnings plus income taxes and interest expense, divided by the sum of interest expense and capitalized interest on debt.

(7) Equal to funds from operations plus current income tax and interest expense, divided by the sum of interest expense and capitalized interest on debt.

Cash Flow provided by Operating Activities

Cash flow provided by operating activities was $10.421 billion in 2019 compared to $10.580 billion in 2018. Cash flow provided by operating activities was positively impacted by the improved western Canadian crude oil differentials, including a substantial narrowing of heavy crude and SCO differentials, from the prior year which led to an increase in Oil Sands price realizations. Cash flow provided by operating activities in 2019 was also positively impacted by higher overall upstream production despite mandatory curtailments as well as after-tax insurance proceeds of $264 million related to the company's assets in Libya. These factors were more than offset by lower refining margins and an increase in expenses associated with the increased production, and reflected a use of cash from the company's working capital balances in 2019, as compared to a source of cash in 2018.

Cash Flow used in Investment Activities

Cash flow used in investing activities was $5.088 billion in 2019 compared to $6.697 billion in 2018. The decrease was primarily due to less acquisition activity in 2019 compared to the prior year, which included the purchase of an additional 5% interest in Syncrude. This was partially offset by an increase in capital and exploration expenditures and other investments.

Cash Flow used in Financing Activities

Cash flow used in financing activities was $5.537 billion in 2019, compared to $4.426 billion in 2018. The increase was primarily due to a net decrease in short-term debt, lease liability payments, and an increase in dividends paid, partially offset by a decrease in the purchase of the company's own common shares under its normal course issuer bid (NCIB), and a net increase of long-term debt in 2019.

Management of debt levels continues to be a priority for Suncor given the company's long-term growth plans and future expected volatility in the pricing environment. Suncor believes a phased and flexible approach to existing and future growth projects should assist the company in maintaining its ability to manage project costs and debt levels.

Capital Resources

Suncor's capital resources consist primarily of cash flow provided by operating activities, cash and cash equivalents

and available credit facilities, including commercial paper. Suncor's management believes the company will have the capital resources to fund its planned 2020 capital spending program of $5.4 to $6.0 billion and to meet current and future working capital requirements through cash and cash equivalents balances, cash flow provided by operating activities, available committed credit facilities, issuing commercial paper and accessing capital markets. The company's cash flow provided by operating activities depends on a number of factors, including commodity prices, production and sales volumes, refining and marketing margins, operating expenses, taxes, royalties and foreign exchange rates.

The company has invested excess cash in short-term financial instruments that are presented as cash and cash equivalents. The objectives of the company's short-term investment portfolio are to ensure the preservation of capital, maintain adequate liquidity to meet Suncor's cash flow requirements and deliver competitive returns derived from the quality and diversification of investments within acceptable risk parameters. The maximum weighted average term to maturity of the short-term investment portfolio is not expected to exceed six months, and all investments will be with counterparties with investment grade debt ratings.

Available Sources of Liquidity

Cash and Cash Equivalents

Included in cash and cash equivalents of $1.960 billion at December 31, 2019 are short-term investments with weighted average days to maturity of approximately 17 days. In 2019, the company earned approximately $38 million of interest income on these investments.

Financing Activities

Suncor's interest on debt and lease liabilities (before capitalized interest) in 2019 was $997 million, an increase from $897 million in 2018, due to the issuance of $750 million of new debt, the transition to IFRS 16 and the unfavourable impact of a weaker average Canadian dollar on U.S. dollar denominated debt, partially offset by the significant decrease in short-term debt in 2019 and the repayment of US$140 million of higher interest rate long-term debt.

Available lines of credit at December 31, 2019 increased to $4.701 billion, compared to $3.608 billion at December 31, 2018, primarily as a result of the repayment of short-term indebtedness.

A summary of total and unutilized credit facilities at December 31, 2019 is as follows:

($ millions)	2019
Fully revolving and expires in 2023	3 500
Fully revolving and expires in 2022	3 241
Fully revolving and expires in 2021	1 455
Can be terminated at any time at the option of the lenders	132
Total credit facilities	8 328
Credit facilities supporting outstanding commercial paper	(2 155)
Credit facilities supporting standby letters of credit	(1 284)
Total unutilized credit facilities[(1)]	4 889

(1) Available credit facilities for liquidity purposes were $4.701 billion at December 31, 2019 (December 31, 2018 – $3.608 billion).

Total Debt to Total Debt Plus Shareholders' Equity

Suncor is subject to financial and operating covenants related to its bank debt and public market debt. Failure to meet the terms of one or more of these covenants may constitute an Event of Default as defined in the respective debt agreements, potentially resulting in accelerated repayment of one or more of the debt obligations. The company is in compliance with its financial covenant that requires total debt to not exceed 65% of its total debt plus shareholders' equity. At December 31, 2019, total debt to total debt plus shareholders' equity was 29.9% (December 31, 2018 – 28.3%) and increased due to the implementation of IFRS 16 and impairment charges recorded in 2019. The company is currently in compliance with all operating covenants as at December 31, 2019.

At December 31 ($ millions, except as noted)	2019	2018[(1)]
Short-term debt	**2 155**	3 231
Current portion of long-term debt	**—**	191
Current portion of long-term lease liabilities	**310**	38
Long-term debt	**12 884**	12 668
Long-term lease liabilities	**2 621**	1 222
Total debt	**17 970**	17 350
Less: Cash and cash equivalents	**1 960**	2 221
Net debt	**16 010**	15 129
Shareholders' equity	**42 042**	44 005

Total debt plus shareholders' equity	**60 012**	61 355
Total debt to total debt plus shareholders' equity (%)	**29.9**	28.3

(1) Excludes the impact of IFRS 16, which was prospectively adopted on January 1, 2019 in accordance with the standard.

Change in Net Debt

($ millions)	
Total debt – December 31, 2018	17 350
Increase in long-term debt	557
Decrease in short-term debt	(982)
January 1, 2019 increase in lease liabilities associated with IFRS 16	1 792
Increase in lease liability during the year	186
Lease payments	(307)
Foreign exchange on debt, and other	(626)
Total debt – December 31, 2019	17 970
Less: Cash and cash equivalents – December 31, 2019	1 960
Net debt – December 31, 2019	16 010

At December 31, 2019, Suncor's net debt was $16.010 billion, compared to $15.129 billion at December 31, 2018. During 2019, total debt increased by $620 million, primarily due to the impact of the adoption of IFRS 16, which added $1.792 billion in lease liability to the company's balance sheet, a net increase in long-term debt and additional leases entered into in 2019, partially offset by the repayment of $982 million of short-term debt, favourable foreign exchange rates on U.S. dollar denominated debt, as compared to December 31, 2018, and lease principal payments made in 2019.

For the year ended December 31, 2019, the company's net debt to funds from operations measure was 1.5 times, which is lower than management's maximum target of less than 3.0 times.

Credit Ratings

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

As at February 26, 2020, the company's long-term senior debt ratings are:

Long-Term Senior Debt	Rating	Long-Term Outlook
Standard & Poor's	A-	Stable
Dominion Bond Rating Service	A (low)	Stable
Moody's Investors Service	Baa1	Stable

As at February 26, 2020, the company's commercial paper ratings are:

Commercial Paper	Cdn Program Rating	U.S. Program Rating
Standard & Poor's	A-1 (low)	A-2
Dominion Bond Rating Service	R-1 (low)	Not rated
Moody's Investors Service	Not rated	P2

Refer to the Description of Capital Structure – Credit Ratings section of Suncor's 2019 AIF for a description of credit ratings listed above.

Common Shares

Outstanding Shares

(thousands)	December 31, 2019
Common shares	**1 531 874**
Common share options – exercisable	**21 535**
Common share options – non-exercisable	**12 347**

As at February 25, 2020, the total number of common shares outstanding was 1,526,810,321 and the total number of exercisable and non-exercisable common share options outstanding was 33,019,526. Once exercisable, each outstanding common share option may be exercised for one common share.

Share Repurchases

In May 2019, Suncor renewed its NCIB to continue to repurchase its common shares through the facilities of the Toronto Stock Exchange (TSX), New York Stock Exchange and/or alternative trading platforms between May 6, 2019 and May 5, 2020. In December 2019, following the approval by Suncor's Board of Directors to increase the company's share repurchase program to $2.5 billion, the TSX accepted a notice filed by Suncor of its intention to amend its NCIB effective as of December 30, 2019. The notice provided that Suncor may increase the maximum number of common shares that may be purchased for cancellation between May 6, 2019 and May 5, 2020 from 50,252,231 common shares, or approximately 3% of Suncor's issued and outstanding common shares as at April 30, 2019, to

78,549,178 common shares, or approximately 5% of Suncor's issued and outstanding common shares as at April 30, 2019. Suncor security holders may obtain a copy of the notice, without charge, by contacting the company.

Since commencing its share buyback program in 2011, Suncor has purchased 316,307,436 common shares as of February 25, 2020 for a total return to shareholders of $12.4 billion under this program, with close to half of these share repurchases occurring in the last 3 years. Subsequent to the end of the year, Suncor's Board of Directors approved a further share repurchase program of up to $2 billion.

At December 31 ($ millions, except as noted)	**2019**	2018	2017
Share repurchase activities (thousands of common shares)			
Shares repurchased	**55 298**	64 426	33 153
Share repurchase cost	**2 274**	3 053	1 413
Weighted average repurchase price per share (dollars per share)	**41.12**	47.38	42.61

Contractual Obligations, Commitments, Guarantees, and Off-Balance Sheet Arrangements

In addition to the enforceable and legally binding obligations in the table below, Suncor has other obligations for goods and services that were entered into in the normal course of business, which may terminate on short notice, including commitments for the purchase of commodities for which an active, highly liquid market exists, and which are expected to be re-sold shortly after purchase.

The company does not believe it has any guarantees or off-balance sheet arrangements that have, or are reasonably likely to have, a current or future material effect on the company's financial condition or financial performance, including liquidity and capital resources.

In the normal course of business, the company is obligated to make future payments, including contractual obligations and non-cancellable commitments.

	Payment due by period						
($ millions)	2020	2021	2022	2023	2024	Thereafter	Total
Fixed and revolving term debt [1]	722	2 127	864	625	1 594	17 183	**23 115**
Decommissioning and restoration costs[2]	482	230	252	239	241	11 492	**12 936**
Long-term contracts, pipeline capacity and energy services commitments[3]	1 772	1 372	1 305	1 315	1 229	10 084	**17 077**
Exploration work commitments	7	44	—	—	—	465	**516**
Other long-term obligations[4]	2	20	20	20	19	—	**81**
Total[5]	**2 985**	**3 793**	**2 441**	**2 199**	**3 083**	**39 224**	**53 725**

(1) Includes debt that is redeemable at Suncor's option and interest payments on fixed-term debt.

(2) Represents the undiscounted amount of decommissioning and restoration costs.

(3) The company has also entered into a pipeline commitment of $5.9 billion with a contract term of 20 years, which is awaiting regulatory approval.

(4) Includes Libya EPSA signature bonus and merger consent. Please refer to note 21 to Suncor's 2019 audited Consolidated Financial Statements.

(5) As a result of the adoption of IFRS 16 on January 1, 2019, finance lease obligations and operating leases are no longer represented above. Please refer to note 5 to Suncor's 2019 audited Consolidated Financial Statements for further details.

Transactions with Related Parties

The company enters into transactions with related parties in the normal course of business. These transactions primarily include sales to associated entities in the company's R&M segment and service provisions to Fort Hills. For more information on these transactions and for a summary of Compensation of Key Management Personnel, refer to note 30 to the 2019 audited Consolidated Financial Statements.

Financial Instruments

The company uses derivative financial instruments, such as physical and financial contracts, to manage certain exposures to fluctuations in interest rates, commodity prices and foreign currency exchange rates, as part of its overall risk management program, as well as for trading purposes. For the year ended December 31, 2019, the pre-tax earnings impact of risk management and trading activities was $155 million (2018 – pre-tax earnings of $255 million).

Gains or losses related to derivatives are recorded as Other Income in the Consolidated Statements of Comprehensive Income.

($ millions)	2019	2018
Fair value outstanding, beginning of year	**60**	(105)
Cash settlements – received during the year	**(254)**	(90)
Changes in fair value recognized in earnings during the year	**155**	255
Fair value outstanding, end of year	**(39)**	60

The fair value of derivative financial instruments is recorded on the Consolidated Balance Sheets.

Fair value of derivative contracts at December 31 ($ millions)	2019	2018
Accounts receivable	**94**	215
Accounts payable	**(133)**	(155)
	(39)	60

Risks Associated with Derivative Financial Instruments

Suncor may be exposed to certain losses in the event that counterparties to derivative financial instruments are unable to fulfil their obligations under these contracts. The company minimizes this risk by entering into agreements with investment grade counterparties. Risk is also minimized through regular management review of the potential exposure to and credit ratings of such counterparties. Suncor's exposure is limited to those counterparties holding derivative contracts with net positive fair values at a reporting date.

Suncor's risk management activities are subject to periodic reviews by management to determine appropriate hedging requirements based on the company's tolerance for exposure to market volatility, as well as the need for stable cash flow to finance future growth. Commodity risk management and trading activities are governed by a separate risk management group that reviews and monitors practices and policies and provides independent verification and valuation of these activities.

For further details on our derivative financial instruments, including assumptions made in the calculation of fair value, a sensitivity analysis of the effect of changes in commodity prices on our derivative financial instruments, and additional discussion of exposure to risks and mitigation activities, refer to note 26 to the company's 2019 audited Consolidated Financial Statements.

9. ACCOUNTING POLICIES AND CRITICAL ACCOUNTING ESTIMATES

Suncor's significant accounting policies are described in note 3 to the audited Consolidated Financial Statements for the year ended December 31, 2019.

Adoption of New IFRS Standards

IFRS 16 *Leases*

Effective January 1, 2019, the company adopted IFRS 16 which replaces IAS 17 and requires the recognition of most leases on the balance sheet. IFRS 16 effectively removes the classification of leases as either finance or operating leases and treats all leases as finance leases for lessees with optional exemptions for short-term leases where the term is twelve months or less. The accounting treatment for lessors remains essentially unchanged, with the requirement to classify leases as either finance or operating.

The company has selected the modified retrospective transition approach, electing to adjust opening retained earnings with no restatement of comparative figures. As such, comparative information continues to be reported under IAS 17 and IFRIC 4. The details of accounting policies under IAS 17 and IFRIC 4 are disclosed separately if they are different from those under IFRS 16 and the impact of the change is disclosed below.

The company's accounting policy under IFRS 16 is as follows:

At inception of a contract, the company assesses whether a contract is, or contains, a lease based on whether the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration.

The company recognizes a right-of-use asset and a lease liability at the lease commencement date. The right-of-use asset is initially measured based on the initial amount of the lease liability adjusted for any lease payments made at or before the commencement date, plus any initial direct costs incurred and an estimate of costs to dismantle and remove the underlying asset or to restore the underlying asset or the site on which it is located, less any lease incentives received. The assets are depreciated to the earlier of the end of the useful life of the right-of-use asset or the lease term, where judgment is applied to determine the lease term of the lease contracts in which the company has a renewal option, using the straight-line method as this most closely reflects the expected pattern of consumption of the future economic benefits. In addition, the right-of-use assets may be periodically reduced by impairment losses, if any, and adjusted for certain remeasurements of the lease liability.

The lease liability is initially measured at the present value of the lease payments that are not paid at the commencement date, discounted using the interest rate implicit in the lease or, if that rate cannot be readily determined, the company's incremental borrowing rate. Lease payments include fixed payments, and variable payments that are based on an index or rate.

Cash payments for the principal portion of the lease liability are presented within the financing activities section and the interest portion of the lease liability is presented within the operating activities section of the statement of cash flows. Short-term lease payments and variable lease payments not included in the measurement of the lease liability are presented within the operating activities section of the statement of cash flows.

The lease liability is measured at amortized cost using the effective interest method. It is remeasured when there is a change in future lease payments arising from a change in an index or rate, if there is a change in the company's estimate of the amount expected to be payable under a residual value guarantee, or if the company changes its assessment of whether it will exercise a purchase, extension or termination option.

When the lease liability is remeasured in this way, a corresponding adjustment is made to the carrying amount of the right-of- use asset, or is recorded in profit or loss if the carrying amount of the right-of-use asset has been reduced to zero.

Under IAS 17

In the comparative period, the company classified leases that transferred substantially all of the risks and rewards of ownership as finance leases. When this was the case, the leased assets were measured initially at an amount equal to the lower of their fair value and the present value of minimum lease payments. Minimum lease payments were the payments over the lease term that the lessee was required to make, excluding any contingent rent.

Subsequently, the assets were accounted for in accordance with the accounting policy applicable to that asset.

Assets held under other leases were classified as operating leases and were not recognized in the company's statement of financial position. Payments made under operating leases were recognized in profit or loss on a straight-line basis over the term of the lease. Lease incentives received were recognized as an integral part of the total lease expense over the term of the lease.

As part of the initial application of IFRS 16, the company also chose to apply the following transitional provisions:

Right-of-use assets are measured at:

- An amount equal to the lease liability on January 1, 2019, adjusted by the amount of any prepaid or accrued lease payments relating to that lease recognized in the statement of financial position immediately before the date of transition.

The company applied the following practical expedients when applying IFRS 16 to leases previously classified as operating leases under IAS 17:

- Adjusted the right-of-use assets by the amount of any provision for onerous leases recognized in the balance sheet immediately before the date of initial application, as an alternative to performing an impairment review.
- Elected not to recognize right-of-use assets and lease liabilities for short-term leases that have a lease term of twelve months or less and leases with a short-term remaining life upon adoption. The lease payments associated with these leases are recognized as an expense on a straight-line basis over the lease term.
- Accounted for each lease component and any non-lease components as a single lease component for crude oil storage tanks.
- Used hindsight to determine the lease term if the contract contained options to extend or terminate the lease.

The following table summarizes the impact of adopting IFRS 16 on the company's Consolidated Balance Sheets at January 1, 2019. Prior period amounts have not been restated. The effects of the transition have been recognized through retained earnings in equity.

($ millions) Increase (Decrease)	December 31 2018	Adjustments due to IFRS 16	January 1 2019
Assets			
Current assets			
Accounts receivable	3 206	(2)	3 204
Property, plant and equipment, net	74 245	(1 267)	72 978
Right-of-use assets, net	—	3 059	3 059
Liabilities and Shareholders' Equity			
Current liabilities			
Current portion of long-term debt	229	(38)	191
Current portion of lease liabilities	—	276	276
Current portion of provisions	667	(1)	666
Long-term debt	13 890	(1 222)	12 668
Long-term lease liabilities	—	2 777	2 777
Other long-term liabilities	2 346	(1)	2 345
Provisions	6 984	(20)	6 964
Deferred income taxes	12 045	5	12 050
Equity	44 005	14	44 019

The following table reconciles the company's operating lease commitments as at December 31, 2018, as previously disclosed in the company's Consolidated Financial Statements as at and for the year ended December 31, 2018, to the additional lease liabilities recognized on initial application of IFRS 16 as at January 1, 2019.

Reconciliation

($ millions)	January 1 2019
Operating leases as at December 31, 2018 (1)	2 457
Exemption for short-term leases	(42)
Discounting	(623)
Additional lease liabilities recognized due to adoption of IFRS 16 as at January 1, 2019	1 792

(1) Represents undiscounted lease commitments.

For leases that were previously classified as finance leases under IAS 17, within Property, Plant and Equipment, the carrying amount of the right-of-use asset and the lease liability recognized upon initial application as at January 1, 2019 was determined to be the carrying amount of the finance lease asset and liability under IAS 17 immediately before transition.

The lease liabilities recognized in accordance with IFRS 16 were discounted using the company's incremental borrowing rate upon initial application. The weighted average discount rate used for additional leases recognized as a result of application of IFRS 16 was 3.85% as at January 1, 2019.

Uncertainty over Income Tax Treatments

In June 2017, the IASB issued IFRIC 23 *Uncertainty over Income Tax Treatments*. The interpretation clarifies the accounting for current and deferred tax liabilities and assets in circumstances in which there is uncertainty over income tax treatments. The interpretation requires an entity to consider whether it is probable that a taxation authority will accept an uncertain tax treatment. If the entity considers it to be not probable that a taxation authority will accept an uncertain tax provision, the interpretation requires the entity to use the most likely amount or the expected value. The company adopted the amendment on its effective date of January 1, 2019. The adoption of this amendment did not have any impact on the company's consolidated financial statements.

Recently Announced Accounting Pronouncements

The standards, amendments and interpretations that are issued, but not yet effective up to the date of authorization of the company's 2019 audited Consolidated Financial Statements, and that may have an impact on the disclosures and financial position of the company are disclosed below. The company intends to adopt these standards, amendments and interpretations when they become effective.

Definition of a Business

In October 2018, the IASB issued *Definition of a Business (Amendments to IFRS 3)*. The amendments narrowed and clarified the definition of a business. The amendments include an election to use a concentration test. This is a simplified assessment that results in an asset acquisition if substantially all of the fair value of the gross assets is concentrated in a single identifiable asset or a group of similar identifiable assets. If an election to use a concentration test is not made, or the test failed, then the assessment focuses on the existence of a substantive process. One important distinction is that "goodwill" can only be recognized as a result of acquiring a business, but not as a result of an asset acquisition. The amendments are effective for annual periods beginning on or after January 1, 2020 and are to be applied prospectively.

Significant Accounting Estimates and Judgments

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

Oil and Gas Reserves

The company's estimate of oil and gas reserves is considered in the measurement of depletion, depreciation, impairment, and decommissioning and restoration obligations. The estimation of reserves is an inherently complex process and involves the exercise of professional judgment. All reserves have been evaluated at December 31, 2019 by independent qualified reserves evaluators. Oil and gas reserves estimates are based on a range of geological, technical and economic factors, including projected future rates of production, projected future commodity prices, engineering data, and the timing and amount of future expenditures, all of which are subject to uncertainty. Estimates reflect market and regulatory conditions existing at December 31, 2019, which could differ significantly from other points in time throughout the year, or future periods. Changes in market and regulatory conditions and assumptions can materially impact the estimation of net reserves.

Oil and Gas Activities

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

Exploration and Evaluation Costs

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

Determination of Cash Generating Units (CGUs)

A CGU is the lowest grouping of integrated assets that generate identifiable cash inflows that are largely independent of the cash inflows of other assets or groups of assets. The allocation of assets into CGUs requires significant judgment and interpretations with respect to the integration between assets, the existence of active markets, similar exposure to market risks, shared infrastructure, and the way in which management monitors the operations.

Asset Impairment and Reversals

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

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

Decommissioning and Restoration Costs

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

Actual costs are uncertain and estimates may vary as a result of changes to relevant laws and regulations related to the use of certain technologies, the emergence of new technology, operating experience, prices and closure plans. The estimated timing of future decommissioning and restoration may change due to certain factors, including reserves life. Changes to estimates related to future expected costs, discount rates, inflation assumptions, and timing may have a material impact on the amounts presented.

Employee Future Benefits

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

Other Provisions

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

Income Taxes

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

Deferred Income Taxes

Deferred tax assets are recognized when it is considered probable that deductible temporary differences will be recovered in the foreseeable future. To the extent that future taxable income and the application of existing tax laws in each jurisdiction differ significantly from the company's estimate, the ability of the company to realize the deferred tax assets could be impacted.

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

Fair Value of Financial Instruments

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

Functional Currency

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

10. RISK FACTORS

Suncor is committed to a proactive program of enterprise risk management intended to enable decision-making through consistent identification and assessment of risks inherent to its assets, activities and operations. Some of these risks are common to operations in the oil and gas industry as a whole, while some are unique to Suncor. The realization of any of the following risks could have a material adverse effect on Suncor's business, financial condition, reserves and results of operations.

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 and electricity prices in the company's upstream business where natural gas and power are both inputs and outputs 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 (particularly in emerging markets), market access constraints, regional and international supply and demand imbalances, political developments and government action (including the mandatory production curtailments recently imposed by the Government of Alberta), decisions by OPEC to not impose quotas on its members, compliance or non-compliance with quotas agreed upon by OPEC members and other countries, 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, market access, 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, reserves and results of operations.

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, reserves and results of operations.

In the fourth quarter of 2018, there was insufficient market access capacity to remove production from the Western Canada Sedimentary Basin causing the differential between WTI and WCS to widen significantly. The situation triggered a response from the Government of Alberta in the form of a mandatory production curtailment, which commenced in early 2019. Such circumstances may result in worsening and/or prolonged price volatility and/or further negative impacts on market dynamics that cannot currently be fully anticipated. Wide differentials, such as those experienced in the fourth quarter of 2018 or 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, reserves and results of operations, and may also lead to the impairment of assets, or to the cancellation or deferral of Suncor's growth projects.

Market Access

Suncor's production of bitumen is expected to grow. The markets for bitumen blends or heavy crude oil are more limited than those for light crude oil, 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.

Market access for Suncor's 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 could create widening differentials that could impact the profitability of product sales. Market access for refined products may also be constrained by insufficient takeaway capacity, which could create a supply/demand imbalance. 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.

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 and decommissioning of facilities, and carries the additional economic risk associated with operating reliably or enduring a protracted operational outage. The breadth and level of integration of Suncor's operations adds complexity.

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, delays in resuming normal operations, 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, prolonged periods of extreme cold or extreme heat, severe winter climate conditions, 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 (including information technology and related data and controls systems), and the environment.

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 the company's policies, standards and 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, network or cyber 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;
- Suncor's 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. Harsh weather conditions, particularly in the winter season, may also impact the successful execution of maintenance and startup of operations. Suncor's E&P offshore operations could be indirectly affected by catastrophic events occurring at other third-party offshore operations, which 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 comprehensive coverage in all circumstances, nor are all such risks insurable. The company self-insures some risks, and the company's insurance coverage does not cover all 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.

Government/Regulatory and Policy Effectiveness

Suncor's businesses operate under federal, provincial, territorial, state and municipal laws in numerous countries. The company 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 (including restrictions on production), 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, mine financial security requirements, approval of logistics infrastructure, and possibly expropriation or cancellation of contract rights. As part of ongoing operations, the company is also required to comply with a large number of EH&S regulations under a variety of Canadian, U.S., U.K., Norwegian 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 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, Indigenous and stakeholder consultation, environmental impact assessments and public hearings, government intervention and may be subject to conditions, including security deposit obligations and other commitments. 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, licences and approvals, or failure to obtain them on a timely basis or on satisfactory terms, could result in prosecution, fines, 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. 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.

Changes in government policy, 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 less profitable or 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 Indigenous consultation requirements as well as increased political involvement. The federal government's *Impact Assessment Act* (formerly Bill C-69) also came into force in August 2019 and will impact the manner in which large energy projects are approved. This development could also lead to significant delays and 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, permit approvals, and project development and execution, all of which could have a material adverse effect on Suncor's business, financial condition, reserves and results of operations.

Suncor is subject to the mandatory production curtailments imposed by the Government of Alberta that commenced in early 2019. The duration, extent and consequences of the curtailments to Suncor's business are not fully known; however, prolonged production curtailment or changes to the curtailment levels could have a material adverse effect on Suncor's business, financial condition, reserves and results of operations.

Greenhouse Gas Emissions and Targets

Among other sustainability goals, Suncor has committed to reducing the total GHG emissions intensity of its oil and gas petroleum products by 30% by 2030 (based on a 2014 baseline year). Our ability to lower GHG emissions on both an absolute basis and in respect of our 2030 total emissions reduction target is subject to numerous risks and uncertainties and our actions taken in implementing these objectives may also expose us to certain additional and/or heightened financial and operational risks.

A reduction in GHG emissions relies on, among other things, our ability to implement and improve energy efficiency at all of our facilities, future development and growth opportunities, develop and deploy new technologies, invest in low-carbon power and transition to low-carbon fuels. In the event that we are unable to implement these strategies and technologies as planned without negatively impacting our expected operations or business plans, or in the event that such strategies or technologies do not perform as expected, we may be unable to meet our GHG targets or goals on the current timelines, or at all.

In addition, achieving our GHG emission reductions target and goals could require significant capital expenditures and resources, with the potential that the costs required to achieve our target and goals materially differ from our original estimates and expectations, which differences may be material. In addition, the shift in resources and focus towards emissions reduction could have a negative impact on our operating results. The overall final cost of investing in and implementing an emissions-intensity reduction strategy and technologies in furtherance of such strategy, and the resultant change in the deployment of our resources and focus, could have a material adverse effect on Suncor's business, financial condition, reserves 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, 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. Although current commodity pricing and increased regulatory requirements have slowed certain larger projects in the short term, an increase in the level of activity may have an impact on regional infrastructure, including pipelines, and could place 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, and impact demand for Suncor's products, which could have a material adverse effect on Suncor's business, financial condition and results of operations.

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.

Existing and future laws and regulations may impose significant liabilities on a failure to comply with their requirements. Concerns over climate change, fossil fuel extraction, GHG emissions, and water and land-use practices 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.

Changes to environmental regulations, 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, abandonment and reclamation obligations and distribution costs, which may not be recoverable in the marketplace and which may result in current operations or growth projects becoming less profitable or 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 or obtain regulatory approvals for these technology projects could prevent Suncor from obtaining regulatory approvals for projects or being able to successfully compete with other companies. Increasing environmental regulation in the jurisdictions in which Suncor operates may also make it difficult for Suncor to compete with companies operating in other jurisdictions with fewer or less costly regulations. In addition, legislation or policies that limit the purchase of production from the oil sands may be adopted in domestic and/or foreign jurisdictions, which, in turn, may limit the world market for Suncor's upstream production and reduce the prices the company receives for its products, and could result in delayed development, stranded assets or the company being unable to further develop its resources. The complexity, breadth and velocity of changes in environmental regulation make it extremely difficult to predict the potential impact to Suncor.

Suncor continues to 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 may rise as a result of growth. 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, including litigation pertaining to GHG emissions, the production, sale, or promotion of fossil fuels and petroleum products, and/or disclosure. For example, the Board of County Commissioners of Boulder County, the Board of County Commissioners of San Miguel County and the City of Boulder, all of Colorado, have brought an action against Suncor and certain of its subsidiaries seeking, among other things, compensation for impacts they allege with respect 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 future developments 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 and Water Release

Each oil sands mine is required under the Tailings Directive to seek approval for its updated fluid tailings management plans. If a mine fails to meet a condition of its approved plan, 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, the Tailings Directive and updates to the dam regulations, including the financial consequences of exceeding compliance levels, is not yet fully known, as certain associated policy updates and regulation updates are still under development. Such updates could also restrict the technologies that the company may employ for tailings management, which could adversely impact the company's business plans. There could also be risks if the company's tailings management operations fail to operate as anticipated. The occurrence of any of the foregoing could have a material adverse effect on Suncor's business, financial condition, reserves and results of operations.

In addition, an integrated water management approach to support operations and successful reclamation and closure requires the release of treated oil sands mine water to the environment, which is not currently permitted for oil sands mines under existing laws. There is no certainty as to when regulations authorizing such water release would be enacted, the content of any such regulations, and the ability of and timing for the company to obtain the required approvals under such regulations to permit such water release. The absence of effective government regulations in this area could impact the success and timing of closure and reclamation plans, which 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 a material 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 in a timely manner 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 obligated 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 Suncor operations and growth projects will 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.

Information Security

The efficient operation of Suncor's business is dependent on computer hardware, software and networked systems, including the systems of cloud providers and third parties with which Suncor conducts business. Digital transformation continues to increase the number of, and complexity of, such systems. In the ordinary course of Suncor's business, Suncor collects and stores sensitive data, including intellectual property, proprietary business information and 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. While Suncor has an information and cyber security program in place, the measures, controls and technology on which the company relies may not be adequate due to the increasing volume, sophistication and rapidly evolving nature 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, including natural disasters and acts of war. 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, physical harm to people or the environment, or other negative consequences to Suncor or third parties, 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.

Security and Terrorist Threats

Security threats and terrorist or activist activities may impact Suncor's personnel, which could result in injury, death, extortion, hostage situations and/or kidnapping, including unlawful confinement. A security threat, terrorist attack or activist incident targeted at a facility or office owned or operated by Suncor could result in the interruption or cessation of key elements of Suncor's operations. Outcomes of such incidents could have a material adverse effect on Suncor's business, financial condition, reserves and results of operations.

Project Development and Execution

There are certain risks associated with the development and execution of Suncor's major projects and the commissioning and integration of new facilities within its existing asset base.

Project development and execution risk consists of four related primary risks:

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

Project development and execution can also be impacted by, among other things:

- The effect of changing government regulation and public expectations in relation to the impact of oil sands development on the environment, which could significantly impact the company's 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 complexity and diversity of Suncor's portfolio, including joint venture assets;

- The accuracy of project cost and schedule estimates, as actual costs and schedules for major projects can vary from estimates, and these differences can be material;
- The availability and cost of materials, equipment, qualified personnel, and logistics infrastructure, maintaining adequate quality management and risks associated with logistics and offshore fabrication, including the cost of materials, and equipment fabricated offshore may be impacted by tariffs, duties and quotas;
- The inability or unwillingness of third-party vendors, contractors or service providers to provide materials, equipment, personnel and services of necessary quality in the timelines anticipated and at the agreed upon cost;
- The complexities and uncertainties associated with identification, development and integration of new technologies into the company's existing and new assets;
- Complexities and risks associated with constructing projects within operating environments and confined construction areas;
- The commissioning and integration of new facilities within the company's existing asset base could cause delays in achieving guidance, targets and objectives;
- Risks relating to restarting projects placed in safe mode, including increased capital costs; and
- The impact of weather conditions.

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 sustainability, 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, or that third-party intellectual property protections may impede the development and implementation of new technology. 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.

Cumulative Impact and Pace 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. The establishment of the Transformation Management Office to support Suncor's digital transformation is expected to assist with the transformation, but there is still 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, reserves 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, In Situ assets, 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, scope, funding and/or capital commitments with respect to projects that are being jointly developed.

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 manage its exposure to commodity price and other market risks, creates exposure to 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 2019 audited Consolidated Financial Statements are presented in Canadian dollars. The majority of Suncor's revenues from the sale of oil, natural gas and petroleum products 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 owes a portion of its debt in U.S. dollars. Suncor's financial 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 revenues 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, 2019, the Canadian dollar strengthened in relation to the U.S. dollar to $0.77 from $0.73 at the start of 2019. 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 credit 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 when derivative instruments are 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 and results of operations.

Issuance of Debt and Debt Covenants

Suncor expects that future capital expenditures will be financed out of cash and cash equivalents balances, cash flow provided by operating activities, available committed credit facilities, issuing commercial paper 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 and growth 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 by-laws limit the amount of indebtedness that may be incurred; however, Suncor is subject to covenants in its existing credit 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.

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, levies, tariffs, duties, quotas, 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.

Dividends and Share Repurchases

Suncor's payment of future dividends on its common shares and future share repurchases by Suncor of its common shares will be dependent on, among other things, legislative and stock exchange requirements, the company's financial condition, results of operations, cash flow, the need for funds to finance ongoing operations and growth projects, 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 or repurchase shares in the future.

E&P Reserves Replacement

Suncor's future offshore production, and therefore its cash flows and results of operations from E&P, are highly dependent upon success in exploiting its current reserves base and acquiring or discovering additional reserves. Without additions to its E&P reserves through exploration, acquisition or development activities, Suncor's production from its offshore assets will decline over time as reserves are depleted. The business of exploring for, developing or acquiring reserves is capital intensive. To the extent Suncor's cash flow is insufficient to fund capital expenditures and external sources of capital become limited or unavailable, Suncor's ability to make the necessary capital investments to maintain and expand its reserves will be impaired. In addition, Suncor may be unable to develop or acquire additional reserves to replace its crude oil and natural gas production at acceptable costs.

Uncertainties Affecting Reserves Estimates

There are numerous uncertainties inherent in estimating quantities of reserves, including many factors beyond the company's control. Suncor's actual production, revenues, royalties, taxes, and development and operating expenditures with respect to the company's reserves will vary from its estimates, and such variances could be material.

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 or limited availability by one of these third parties can also have a dramatic impact on Suncor's operations and growth plans. 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.

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, such as that experienced in Libya and Syria, 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 its assets against terrorist activities or to remediate potential damage to its facilities. There can be no assurance that Suncor will be successful in protecting itself against these risks and the related safety and 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.

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 and changing skillsets as technology continues to evolve adds further pressure. The availability of competent and skilled contractors for current and future operations is also a risk depending on market conditions. 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 facilities (excluding MacKay River), all of the company's refineries, and the majority of the company's terminal and distribution operations are represented by labour unions or employee associations. Approximately 31% of the company's employees were covered by collective agreements at the end of 2019. Negotiations for new collective agreements are in progress for two facilities across the company. Any work interruptions involving the company's employees (including as a result of a strike or lockout), 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.

Land Claims and Indigenous Consultation

Indigenous Peoples have claimed Indigenous title and rights to portions of Western Canada. In addition, Indigenous 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 Indigenous Peoples in respect of oil and gas projects and related infrastructure has also increased in recent years. In addition, in recent years, the Canadian federal government and the provincial government in Alberta have made a commitment to renew their relationships with the Indigenous 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". 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 Indigenous Peoples.

Suncor is unable to assess the effect, if any, that any such land claims, consultation requirements with Indigenous 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, disclosure, 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.

Trade Risk Relating to CUSMA

If CUSMA is ratified, Canada will no longer be subject to the proportionality provisions in NAFTA's energy chapter, enabling Canada to expand oil and gas exports beyond the U.S. Further, a change to the oil and gas rules of origin under CUSMA will allow Canadian exporters to more easily qualify for duty-free treatment for shipments to the U.S. Canada must, however, notify the U.S. of its intention to enter into free trade talks with any "non-market economies" under CUSMA, which may include China or any other importers of Canadian oil and gas exports. Although CUSMA has been signed, Canada has yet to ratify CUSMA according to its legislative processes before it goes into effect and replaces NAFTA. The outcome of the ratification process in Canada is not complete and is therefore uncertain. If CUSMA is not ratified and adopted by all three countries, the sale and transportation of Suncor's products within North America could be affected in a manner which could negatively impact Suncor's business, financial condition and results from operations.

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 how Suncor's business, financial condition and results of operations are reported.

Insurance Coverage

Suncor maintains insurance coverage as part of its risk management program. However, such insurance may not provide comprehensive coverage in all circumstances, nor are all such risks insurable. The company self-insures some risks, and the company's insurance coverage does not cover all the costs arising out of the allocation of liabilities and risk of loss arising from Suncor operations.

Suncor's insurance policies are generally renewed on an annual basis and, depending on factors such as market conditions, the premiums, policy limits and/or deductibles for certain insurance policies can vary substantially. In some instances, certain insurance may become unavailable or available only for reduced amounts of coverage. Significantly increased costs could lead the company to decide to reduce, or possibly eliminate, coverage. In addition, insurance is purchased from a number of third-party insurers, often in layered insurance arrangements, some of whom may discontinue providing insurance coverage for their own policy or strategic reasons. Should any of these insurers refuse to continue to provide insurance coverage, the company's overall risk exposure could be increased.

11. OTHER ITEMS

Control Environment

Based on their evaluation as of December 31, 2019, Suncor's Chief Executive Officer and Chief Financial Officer concluded that the company's disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the United States *Securities Exchange Act of 1934*, as amended (the Exchange Act)), are effective to ensure that information required to be disclosed by the company in reports that are filed or submitted to Canadian and U.S. securities authorities is recorded, processed, summarized and reported within the time periods specified in Canadian and U.S. securities laws. In addition, as of December 31, 2019, there were no changes in the internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) that occurred during the year ended December 31, 2019 that have materially affected, or are reasonably likely to materially affect, the company's internal control over financial reporting. Management will continue to periodically evaluate the company's disclosure controls and procedures and internal control over financial reporting and will make any modifications from time to time as deemed necessary.

The effectiveness of our internal control over financial reporting as at December 31, 2019 was audited by KPMG LLP, an independent registered public accounting firm, as stated in their report, which is included in our audited Consolidated Financial Statements for the year ended December 31, 2019.

Based on their inherent limitations, disclosure controls and procedures and internal control over financial reporting may not prevent or detect misstatements, and even those controls determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

Corporate Guidance

There have been no changes to the corporate guidance ranges previously issued on December 2, 2019. For further details and advisories regarding Suncor's 2020 corporate guidance, see www.suncor.com/guidance.

12. ADVISORIES

Non-GAAP Financial Measures

Certain financial measures in this MD&A – namely operating earnings (loss), ROCE, funds from (used in) operations, free funds flow, discretionary free funds flow, Oil Sands operations cash operating costs, In Situ cash operating costs, Fort Hills cash operating costs, Syncrude cash operating costs, refining margin, refining operating expense and LIFO inventory valuation methodology – are not prescribed by GAAP. These non-GAAP financial measures are included because management uses the information to analyze business performance, leverage and liquidity, and it may be useful to investors on the same basis. These non-GAAP financial measures do not have any standardized meaning and, therefore, are unlikely to be comparable to similar measures presented by other companies. Therefore, these non-GAAP financial measures should not be considered in isolation or as a substitute for measures of performance prepared in accordance with GAAP. Except as otherwise indicated, these non-GAAP measures are calculated and disclosed on a consistent basis from period to period. Specific adjusting items may only be relevant in certain periods.

(a) Operating Earnings (Loss)

Operating earnings (loss) is a non-GAAP financial measure that adjusts net earnings (loss) for significant items that are not indicative of operating performance. Management uses operating earnings (loss) to evaluate operating performance, because management believes it provides better comparability between periods. For the years ended December 31, 2019, December 31, 2018 and December 31, 2017, consolidated operating earnings (loss) are reconciled to net earnings (loss) in the Financial Information section of this MD&A and operating earnings (loss) for each segment are reconciled to net earnings (loss) in the Segment Results and Analysis section of the MD&A. Operating earnings (loss) for the three months ended December 31, 2019 and December 31, 2018 are reconciled to net earnings (loss) below.

(b) Bridge Analyses of Operating Earnings

Throughout this MD&A, the company presents charts that illustrate the change in operating earnings from the comparative period through key variance factors. These factors are analyzed in the Operating Earnings narratives following the bridge analyses in that particular section of the MD&A. These bridge analyses are presented because management uses this presentation to analyze performance.

- The factor for Sales Volumes and Mix is calculated based on sales volumes and mix for the Oil Sands and Exploration and Production segments and throughput volumes and mix for the Refining and Marketing segment.
- The factor for Price, Margin and Other Revenue includes upstream price realizations before royalties, with the exception of Libya, which is net of royalties. Also included are refining and marketing margins, other operating revenues, and the net impacts of sales and purchases of third-party crude, including product purchased for use as diluent in the company's Oil Sands operations and subsequently sold as part of diluted bitumen.
- The factor for Royalties excludes the impact of Libya, as royalties in Libya are taken into account in Price, Margin and Other Revenue as described above.
- The factor for Inventory Valuation includes the after-tax impact of the FIFO method of inventory valuation in the company's R&M segment, as well as the impact of the deferral or realization of profit or loss on crude oil sales from the Oil Sands segment to Suncor's refineries, as both represent inventory valuation adjustments.
- The factor for Insurance Proceeds includes the after-tax insurance proceeds related to the company's assets in Libya.
- The factor for Operating and Transportation Expense includes project startup costs, operating, selling and general expense, and transportation expense.
- The factor for Financing Expense and Other includes financing expenses, other income, operational foreign exchange gains and losses, changes in gains and losses on disposal of assets that are not operating earnings adjustments, changes in statutory income tax rates, other income tax adjustments.

(c) Return on Capital Employed (ROCE)

ROCE is a non-GAAP financial measure that management uses to analyze operating performance and the efficiency of Suncor's capital allocation process. Average capital employed is calculated as a twelve-month average of the capital employed balance at the beginning of the twelve-month period and the month-end capital employed balances throughout the remainder of the twelve-month period. Figures for capital employed at the beginning and end of the twelve-month period are presented to show the changes in the components of the calculation over the twelve-month period.

The company presents two ROCE calculations – one including and one excluding the impacts on capital employed of major projects in progress. Major projects in progress includes accumulated capital expenditures and capitalized interest for significant projects still under construction or in the process of being commissioned, and acquired assets that are still being evaluated. Management uses ROCE excluding the impacts of major projects in progress on capital employed to assess performance of operating assets.

Year ended December 31 ($ millions, except as noted)		**2019**	2018	2017
Adjustments to net earnings				
Net earnings attributed to common shareholders		**2 899**	3 293	4 458
Add after-tax amounts for:				
Unrealized foreign exchange (gain) loss on U.S. dollar denominated debt		**(590)**	989	(702)
Net interest expense		**638**	541	158
	A	**2 947**	4 823	3 914
Capital employed – beginning of twelve-month period				
Net debt		**15 129**	12 907	14 414
Shareholders' equity		**44 005**	45 383	44 630
		59 134	58 290	59 044
Capital employed – end of twelve-month period				
Net debt		**16 010**	15 129	12 907
Shareholders' equity		**42 042**	44 005	45 383
		58 052	59 134	58 290
Average capital employed	B	**60 402**	60 347	58 667
ROCE – including major projects in progress (%)	A/B	**4.9**	8.0	6.7
Average capitalized costs related to major projects in progress	C	**2 452**	1 412	12 901
ROCE – excluding major projects in progress (%) [(1)]	A/(B-C)	**5.1**	8.2	8.6

(1) ROCE excluding major projects in progress would have been 8.6% in 2019, excluding the impacts of impairments of $3.352 billion and the impact of the $1.116 billion deferred tax recovery relating to a change in the Alberta corporate income tax rate.

(d) Funds from (used in) Operations [(1)]

Funds from (used in) operations is a non-GAAP financial measure that adjusts a GAAP measure – cash flow provided by (used in) operating activities – for changes in non-cash working capital, which management uses to analyze operating performance and liquidity. Changes to non-cash working capital can include, among other factors, the timing of offshore feedstock purchases and payments for fuel and income taxes, and the timing of cash flows related to accounts receivable and accounts payable, which management believes reduces comparability between periods.

Year ended December 31 ($ millions)	Oil Sands			Exploration and Production			Refining and Marketing		
	2019	2018	2017	**2019**	2018	2017	**2019**	2018	2017
Net (loss) earnings	**(427)**	945	994	**1 005**	807	721	**3 000**	3 154	2 622
Adjustments for:									
Depreciation, depletion, amortization and impairment	**8 170**	4 024	3 782	**1 505**	967	1 028	**823**	684	685
Deferred income taxes	**(1 565)**	351	170	**(215)**	(112)	(113)	**(49)**	72	(147)
Accretion	**221**	209	195	**43**	48	45	**6**	7	7
Unrealized foreign exchange (gain) loss on U.S. dollar denominated debt	**—**	—	—	**—**	—	—	**—**	—	—
Change in fair value of financial instruments and trading inventory	**21**	(59)	13	**16**	(89)	42	**70**	(32)	45
(Gain) loss on disposal of assets	**(14)**	(108)	(50)	**(228)**	91	—	**(11)**	(7)	(354)
Share-based compensation	**16**	(28)	(3)	**—**	(5)	6	**3**	(21)	5
Exploration expenses	**—**	—	—	**66**	11	41	**—**	—	—
Settlement of decommissioning and restoration liabilities	**(413)**	(428)	(305)	**(32)**	(23)	(31)	**(19)**	(17)	(17)
Other	**52**	58	(62)	**(17)**	84	17	**40**	(42)	(23)
Funds from (used in) operations	**6 061**	4 964	4 734	**2 143**	1 779	1 756	**3 863**	3 798	2 823
(Increase) decrease in non-cash working capital									
Cash flow provided by operating activities									

(1) 2018 and 2017 have been restated to reflect the change to the company's segmented presentation of its Energy Trading business, with no impact to overall consolidated results. The Energy Trading business is now included within each of the respective operating business segments to which the respective trading activity relates. Suncor's Energy Trading business was previously reported within the Corporate, Energy Trading and Eliminations segment.

Year ended December 31 ($ millions)	Corporate and Eliminations			Total		
	2019	2018	2017	**2019**	2018	2017
Net (loss) earnings	**(679)**	(1 613)	121	**2 899**	3 293	4 458
Adjustments for:						
Depreciation, depletion, amortization and impairment	**74**	63	106	**10 572**	5 738	5 601
Deferred income taxes	**(89)**	129	339	**(1 918)**	440	249
Accretion	**—**	2	—	**270**	266	247
Unrealized foreign exchange (gain) loss on U.S. dollar denominated debt	**(624)**	1 090	(771)	**(624)**	1 090	(771)
Change in fair value of financial instruments and trading inventory	**—**	1	28	**107**	(179)	128
(Gain) loss on disposal of assets	**—**	—	(70)	**(253)**	(24)	(474)
Share-based compensation	**25**	(63)	23	**44**	(117)	31
Exploration expenses	**—**	—	—	**66**	11	41
Settlement of decommissioning and restoration liabilities	**—**	(1)	—	**(464)**	(469)	(353)
Other	**44**	23	50	**119**	123	(18)
Funds from (used in) operations	**(1 249)**	(369)	(174)	**10 818**	10 172	9 139
(Increase) decrease in non-cash working capital				**(397)**	408	(173)
Cash flow provided by operating activities				**10 421**	10 580	8 966

(1) 2018 and 2017 have been restated to reflect the change to the company's segmented presentation of its Energy Trading business, with no impact to overall consolidated results. The Energy Trading business is now included within each of the respective operating business segments to which the respective trading activity relates. Suncor's Energy Trading business was previously reported within the Corporate, Energy Trading and Eliminations segment.

(e) Free Funds Flow and Discretionary Free Funds Flow

Free funds flow is a non-GAAP financial measure that is calculated by taking funds from operations and subtracting capital expenditures, including capitalized interest. Discretionary free funds flow is a non-GAAP financial measure that is calculated by taking funds from operations and subtracting asset sustainment and maintenance capital, inclusive of associated capitalized interest, and dividends. Discretionary free funds flow reflects cash available for increasing distributions to shareholders and to fund growth investments. Management uses discretionary free funds flow to measure the capacity of the company to increase returns to shareholders and grow the business. The following is a reconciliation of discretionary free funds flow for Suncor's last three years of operations.

($ millions)	**2019**	2018	2017
Funds from operations	**10 818**	10 172	9 139
Asset sustaining and maintenance capital and dividends [(1)]	**(5 904)**	(5 740)	(4 724)
Discretionary free funds flow	**4 914**	4 432	4 415

(1) The classification of the company's capital expenditures has been updated to ``asset sustainment and maintenance" to better reflect the types of capital investments being made by the company. Comparative periods have been updated to reflect this change.

(f) Oil Sands Operations, In Situ, Fort Hills and Syncrude Cash Operating Costs

Oil Sands operations, In Situ, Fort Hills and Syncrude cash operating costs are non-GAAP financial measures. Oil Sands operations cash operating costs are calculated by adjusting Oil Sands segment OS&G expense (a GAAP measure based on sales volumes) for i) costs pertaining to Fort Hills and Syncrude operations; ii) non production costs that management believes do not relate to the production performance of Oil Sands operations, including, but not limited to, share-based compensation adjustments, research and the expense recorded as part of a non-monetary arrangement involving a third-party processor; iii) revenues associated with excess capacity, including excess power generated and sold that is recorded in operating revenue; iv) project startup costs; and v) the impacts of changes in inventory levels, such that the company is able to present cost information based on production volumes. To determine In Situ cash operating costs, Oil Sands operations cash operating costs are further adjusted to remove costs pertaining to Oil Sands operations mining and upgrading. Syncrude and Fort Hills cash operating costs are calculated by adjusting Syncrude OS&G expense and Fort Hills OS&G expense, respectively, for non-production costs that management believes do not relate to the production performance of Syncrude operations or Fort Hills operations, respectively, including, but not limited to, share-based compensation, research and project startup costs, if applicable. Oil Sands operations, Fort Hills and Syncrude cash operating costs are reconciled in the Segment Results and Analysis – Oil Sands section of this document. Management uses cash operating costs to measure operating performance. Oil Sands operations cash operating costs in 2019 were $4.267 billion and included $729 million related to In Situ production for In Situ cash operating costs per barrel of $9.25, based on total In Situ production of 216,200 bbls/d.

(g) Refining Margin and Refining Operating Expense

Refining margin and refining operating expense are non-GAAP financial measures. Refining margin is calculated by adjusting R&M segment operating revenues, other income and purchases of crude oil and products (GAAP measures) for non-refining margin pertaining to the company's supply, marketing and ethanol businesses, and the company's former lubricants business, which was disposed of in early 2017. Refinery operating expense is calculated by adjusting R&M segment OS&G for i) non-refining costs pertaining to the company's supply, marketing and ethanol businesses and the company's former lubricants business; and ii) non-refining costs that management believes do not relate to the production of refined products, including, but not limited to, share-based compensation and enterprise shared service allocations. Management uses refining margin and refining operating expense to measure operating performance on a production barrel basis.

Year ended December 31 ($ millions, except as noted)	**2019**	2018	2017
Refining margin reconciliation			
Gross margin, operating revenues less purchases of crude oil and products	**7 008**	7 122	5 744
Other income	**75**	68	16
Non-refining margin	**(1 320)**	(1 351)	(1 541)
Refining margin	**5 763**	5 839	4 219
Refinery production[(1)] (mbbls)	**173 705**	169 138	174 461
Refining margin ($/bbl)	**33.15**	34.50	24.20
Refining operating expense reconciliation			
Operating, selling and general expense	**2 173**	2 043	2 003
Non-refining costs	**(1 246)**	(1 142)	(1 121)
Refining operating expense	**927**	901	882
Refinery production[(1)]	**173 705**	169 138	174 461
Refining operating expense ($/bbl)	**5.35**	5.35	5.05

(1) Refinery production is the output of the refining process, and differs from crude oil processed as a result of volumetric adjustments for non-crude feedstock, volumetric gain associated with the refining process, and changes in unfinished product inventories.

(h) Impact of First-in, First-out (FIFO) Inventory Valuation on Refining and Marketing Net Earnings

GAAP requires the use of a FIFO valuation methodology. For Suncor, this results in a lag between the sales prices for refined products, which reflects current market conditions, and the amount recorded as the cost of sale for the related refinery feedstock, which reflects market conditions at the time when the feedstock was purchased.

Suncor prepares and presents an estimate of the impact of using a FIFO inventory valuation methodology compared to a LIFO methodology, because management uses the information to analyze operating performance and compare itself against refining peers that are permitted to use LIFO inventory valuation under United States GAAP (U.S. GAAP).

The company's estimate is not derived from a standardized calculation and, therefore, may not be directly comparable to similar measures presented by other companies, and should not be considered in isolation or as a substitute for measures of performance prepared in accordance with GAAP or U.S. GAAP.

(i) Operating Earnings Reconciliations – Fourth Quarter 2019 and 2018 [1]

Three months ended December 31	Oil Sands		Exploration and Production		Refining and Marketing		Corporate and Eliminations		Total	
($ millions)	**2019**	2018	**2019**	2018	**2019**	2018	**2019**	2018	**2019**	2018
Net (loss) earnings as reported	**(2 682)**	(377)	**(162)**	(115)	**558**	762	**(49)**	(550)	**(2 335)**	(280)
Asset Impairments	**2 959**	—	**393**	—	**—**	—	**—**	—	**3 352**	—
Unrealized foreign exchange (gain) loss on U.S. dollar denominated debt	**—**	—	**—**	—	**—**	—	**(235)**	637	**(235)**	637
Non-cash loss on equity investment	**—**	—	**—**	223	**—**	—	**—**	—	**—**	223
Operating earnings (loss)	**277**	(377)	**231**	108	**558**	762	**(284)**	87	**782**	580

(1) The three months ended December 31, 2018 have been restated to reflect the change to the company's segmented presentation of its Energy Trading business, with no impact to overall consolidated results. The Energy Trading business is now included within each of the respective operating business segments to which the respective trading activity relates. Suncor's Energy Trading business was previously reported within the Corporate, Energy Trading and Eliminations segment.

(j) Funds from Operations Reconciliations – Fourth Quarter 2019 and 2018 [1]

Three months ended December 31	Oil Sands		Exploration and Production		Refining and Marketing		Corporate and Eliminations		Total	
($ millions)	**2019**	2018	**2019**	2018	**2019**	2018	**2019**	2018	**2019**	2018
Net (loss) earnings	**(2 682)**	(377)	**(162)**	(115)	**558**	762	**(49)**	(550)	**(2 335)**	(280)
Adjustments for:										
Depreciation, depletion, amortization and impairment	**5 081**	1 019	**803**	199	**211**	184	**18**	17	**6 113**	1 419
Deferred income taxes	**(890)**	89	**(112)**	3	**(7)**	(19)	**7**	87	**(1 002)**	160
Accretion	**54**	53	**10**	12	**1**	2	**—**	—	**65**	67
Unrealized foreign exchange (gain) loss on U.S. dollar denominated debt	**—**	—	**—**	—	**—**	—	**(246)**	688	**(246)**	688
Change in fair value of financial instruments and trading inventory	**(20)**	(84)	**13**	(37)	**(6)**	(27)	**—**	—	**(13)**	(148)
(Gain) loss on disposal of assets	**(1)**	(1)	**—**	253	**(8)**	(2)	**—**	—	**(9)**	250
Share-based compensation	**22**	(22)	**2**	(3)	**11**	(12)	**28**	(51)	**63**	(88)
Exploration expenses	**—**	—	**27**	11	**—**	—	**—**	—	**27**	11
Settlement of decommissioning and restoration liabilities	**(128)**	(91)	**(16)**	(8)	**(7)**	(5)	**—**	—	**(151)**	(104)
Other	**(31)**	21	**(10)**	16	**40**	(10)	**42**	5	**41**	32
Funds from (used in) operations	**1 405**	607	**555**	331	**793**	873	**(200)**	196	**2 553**	2 007
(Decrease) increase in non-cash working capital									**(249)**	1 033
Cash flow provided by operating activities									**2 304**	3 040

(1) The three months ended December 31, 2018 have been restated to reflect the change to the company's segmented presentation of its Energy Trading business, with no impact to overall consolidated results. The Energy Trading business is now included within each of the respective operating business segments to which the respective trading activity relates. Suncor's Energy Trading business was previously reported within the Corporate, Energy Trading and Eliminations segment.

Measurement Conversions

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

Common Abbreviations

The following is a list of abbreviations that may be used in this MD&A:

Measurement

bbl	barrel
bbls/d	barrels per day
mbbls/d	thousands of barrels per day
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
mboe	thousands of barrels of oil equivalent
mboe/d	thousands of barrels of oil equivalent per day
mcf	thousands of cubic feet of natural gas
mcfe	thousands of cubic feet of natural gas equivalent
mmcf	millions of cubic feet of natural gas
mmcf/d	millions of cubic feet of natural gas per day
mmcfe	millions of cubic feet of natural gas equivalent
mmcfe/d	millions of cubic feet of natural gas equivalent per day
m^3	cubic metres
MW	Megawatts
MWh	Megawatt hour

Places and Currencies

U.S.	United States
U.K.	United Kingdom
B.C.	British Columbia
$ or Cdn$	Canadian dollars
US$	United States dollars
£	Pounds sterling
€	Euros

Financial and Business Environment

DD&A	Depreciation, depletion and amortization
WTI	West Texas Intermediate
WCS	Western Canadian Select
SCO	Synthetic crude oil
SYN	Synthetic crude oil benchmark
MSW	Mixed Sweet Blend
NYMEX	New York Mercantile Exchange

Forward-Looking Information

This MD&A 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 development and 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", "priority" and similar expressions.

Forward-looking statements in this MD&A include references to:

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

- *Suncor's strategies and priorities, including delivering competitive and sustainable returns to shareholders and aiming to maximize shareholder returns by focusing on operational excellence, capital discipline through investment in high-value projects and the company's commitment to environmental stewardship and sustainability;*
- *Suncor's belief that it is well positioned to succeed due to its competitive advantages of financial strength, a highly efficient, tightly integrated suite of assets, an*

industry-leading long-life, low-decline oil sands reserves base, an offshore business that provides geographically diversified cash flow and its investment in sustainability, technology and innovation;

- *Projects and initiatives that are expected to create long-term value for the company through structural free funds flow growth, such as improvement strategies at existing assets, like debottlenecks and the deployment of autonomous haul trucks, and the company's regional oil sands advantage, which is expected to provide the company with the economies of scale required to realize synergies between assets and further develop its in situ resources in a low-cost manner under the company's replication strategy;*
- *Suncor's belief that the integration of the company's oil sands assets with its midstream and refining assets helps to significantly shield Suncor from the effects of western Canadian crude price differentials and its midstream assets provide the logistical flexibility to move production to a wide range of markets;*
- *Suncor's belief that technology and unleashing the full potential of its people will be critical in achieving the company's environmental, operational and financial goals;*
- *The company's belief that driving down costs and a continued focus on improved productivity and reliability will help achieve industry-leading unit costs in each business segment;*
- *Suncor's belief that its growth will be fuelled by investments in clean energy and is a key priority in achieving its sustainable development goals;*
- *Statements about the Terra Nova ALE project, including the expectation that it will extend the life of Terra Nova by approximately a decade, that it is planned for execution by the end of 2020 and that work on the project will start in the second quarter of 2020;*
- *Suncor's expectations for the coke-fired boiler replacement project, including the expectation that the cogeneration units will provide reliable steam generation required for Suncor's extraction and upgrading operations, the expectation that it will reduce the GHG emissions intensity associated with steam production at Base Plant by approximately 25% and the estimated cost and in-service date of the project;*
- *Statements about the sanctioned Forty Mile Wind Power Project, including the estimated capital spend of $300 million, with 25% of the capital spend in 2019 and the remainder to be spent over the next two years, the expectation that the project will generate significant value through sustainable low-carbon power generation and retention of the generated carbon credits for utilization in Suncor's upstream business and the belief that the project is part of Suncor's sustainability strategy of making meaningful progress toward the greenhouse gas emissions intensity reduction target of 30% by 2030;*
- *Expectations for the Oil Sands segment, including the commitment to delivering safe, reliable, low-cost production while being leaders in growth, technical innovation and environmental sustainability, the belief that Suncor's collection of high-quality assets, combined with long-life, low-decline reserves and industry-leading expertise provides the opportunity to continue to advance technology and innovation investments and high return growth projects while growing annual free funds flow, the expectation that cost management and capital discipline at Oil Sands will continue to be top priorities as the company expects to sustainably manage controllable operating costs through initiatives and that capital discipline will continue to focus on managing investment opportunities, including asset synergies and sustainability priorities, strategically investing in projects that are economically robust, sustainably minded and technologically progressive, and expectations for the interconnecting pipelines between Syncrude and Suncor's Oil Sands Base Plant, including the expectation that the pipelines will enhance integration between such assets and that they will be in service in the second half of 2020;*
- *Expectations for the E&P segment, including the segment's focus primarily on low-cost projects that deliver significant returns, cash flow and long-term value, and ongoing development activities offshore the east coast of Canada and in the U.K. North Sea intended to leverage existing facilities and infrastructure to provide incremental production and extend the productive life of existing fields which are planned to continue in 2020, along with development drilling at Hebron, the West White Rose Project, Buzzard Phase 2, and the Fenja project;*
- *Statements about the Rosebank project, including the expected timing of sanction for the project being planned for 2022;*
- *The expectation that MacKay River will return to operation early in the second quarter of 2020;*
- *The expectation that the company will continue to accelerate its digital transformation and implement new technologies across the enterprise to help improve the safety, productivity, reliability and environmental performance of its operations and that Suncor will utilize Microsoft's full range of cloud solutions and expertise to empower a connected and collaborative workforce, upgrade data centres and increase analytics capabilities; and*
- *The expectation that well pads under construction will maintain existing production levels at Firebag and*

MacKay River in future years as production from existing well pads declines.

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

- *Planned Upgrader 2 maintenance at Oil Sands Base and annual turnaround at Syncrude in the second quarter of 2020, and maintenance at Oil Sands operations Upgrader 1 scheduled for the third quarter of 2020, extending into the fourth quarter of 2020; and*
- *The two-week turnaround event at the Commerce City refinery in the first quarter of 2020, the two-week turnaround at the Sarnia refinery in the second quarter of 2020, a four-week turnaround at the Edmonton refinery scheduled in the third quarter of 2020 and a six-week turnaround at the Montreal refinery scheduled to begin in the third quarter and extend into the fourth quarter of 2020.*

Also:

- *Economic sensitivities;*
- *The company's priority regarding returning value to shareholders, statements about the company's share repurchase program, and the company's ongoing ability to generate cash flow and commitment to return cash to shareholders;*
- *The company's belief that it does not have any guarantees or off-balance sheet arrangements that have, or are reasonably likely to have, a current or future material effect on the company's financial condition or financial performance, including liquidity and capital resources;*
- *Suncor's planned 2020 capital spending program of $5.4 to $6.0 billion and the belief that the company will have the capital resources to fund its planned 2020 capital spending program and to meet current and future working capital requirements through cash and cash equivalents balances, cash flow provided by operating activities, available committed credit facilities, issuing commercial paper and, if needed, accessing capital markets;*
- *Suncor's expectations as to how its 2020 capital expenditures will be directed and the expected benefits therefrom;*
- *The objectives of the company's short-term investment portfolio and the expectation that the maximum weighted average term to maturity of the company's short-term investment portfolio will not exceed six months, and all investments will be with counterparties with investment grade debt ratings;*
- *Management of debt levels continuing to be a priority for Suncor given the company's long-term growth plans and future expected volatility in the commodity pricing environment, and Suncor's belief that a phased and flexible approach to existing and future growth projects should assist Suncor in maintaining its ability to manage project costs and debt levels;*
- *Suncor's intention to adopt certain accounting standards, amendments and interpretations when they become effective; and*
- *Expectations with respect to changes to law and government policy.*

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, E&P, and R&M, 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; 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 E&P 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; 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 R&M 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; 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 development and execution of Suncor's projects and the commissioning and integration of new facilities; the possibility that completed maintenance activities may not improve operational performance or the output of related facilities; the risk that projects and initiatives intended to achieve cash flow growth and/or reductions in operating costs may not achieve the expected results in the time anticipated or at all; 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, and mandatory production curtailment orders and changes thereto; 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; security threats and terrorist or activist activities; the risk that competing business objectives may exceed Suncor's capacity to adopt and implement change; risks and uncertainties associated with obtaining regulatory, third-party and stakeholder approvals outside of Suncor's control for the company's operations, projects, initiatives, and exploration and development activities and the satisfaction of any conditions to approvals; 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; risks associated with land claims and Indigenous consultation requirements; the risk that the company may be subject 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 MD&A, including under the heading Risk Factors, and the company's 2019 AIF and Form 40-F on file with Canadian securities commissions at www.sedar.com and the United States Securities and Exchange Commission at www.sec.gov. Readers are also referred to the risk factors and assumptions described in other documents that Suncor files from time to time with securities regulatory authorities. Copies of these documents are available without charge from the company.

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

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EXHIBIT 99-2

Management's Discussion and Analysis for the fiscal year ended December 31, 2019, dated February 26, 2020

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EXHIBIT 99-3

Consent of KMPG LLP

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors
Suncor Energy Inc.

We, KPMG LLP, consent to the use of our report, dated February 26, 2020, with respect to the consolidated financial statements and the effectiveness of internal control over financial reporting included in this Annual Report on Form 40-F.

We, KPMG LLP, also consent to the incorporation by reference of such report in the Registration Statements on Form S-8 (No. 333-87604, No. 333-112234, No. 333-118648, No. 333-124415, No. 333-149532, No. 333-161021 and No. 333-161029) and on From F-10 (No. 333-225338) of Suncor Energy Inc.

"*KPMG LLP*"

Chartered Professional Accountants
Calgary, Alberta, Canada
February 27, 2020

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EXHIBIT 99-3

Consent of KMPG LLP

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EXHIBIT 99-4

Consent of PricewaterhouseCoopers LLP

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the inclusion in this Annual Report on Form 40-F for the year ended December 31, 2019 of Suncor Energy Inc. of our report dated February 28, 2019, relating to the Consolidated Financial Statements which appear in this Annual Report.

We also consent to the incorporation by reference in the Registration Statements on Form S-8 (No. 333-87604), Form S-8 (No. 333-112234), Form S-8 (No. 333-118648), Form S-8 (No. 333-124415), Form S-8 (No. 333-149532), Form S-8 (No. 333-161021), Form S-8 (No. 33-161029) and Form F-10 (No. 333-225338) of Suncor Energy Inc. of our report dated February 28, 2019 referred to above.

We also consent to reference to us under the heading "Interests of Experts," which appears in this Annual Report on Form 40-F which is incorporated by reference in such Registration Statements.

"*PricewaterhouseCoopers LLP*"

Chartered Professional Accountants
Calgary, Alberta, Canada
February 27, 2020

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EXHIBIT 99-4

Consent of PricewaterhouseCoopers LLP

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EXHIBIT 99-5

Consent of GLJ Petroleum Consultants Ltd.

LETTER OF CONSENT

TO: Suncor Energy Inc.
The Securities and Exchange Commission
The Securities Regulatory Authorities of Each of the Provinces and Territories of Canada

Dear Sirs/Mesdames:

Re: Suncor Energy Inc. ("Suncor")

We refer to the following reports (the "**Reports**") prepared by GLJ Petroleum Consultants Ltd. ("**GLJ**"):

- Reserves Assessment and Evaluation of In Situ Oil Sands Properties — Corporate Summary dated February 21, 2020; and
- Reserves Assessment and Evaluation of Oil Sands Mining Properties — Corporate Summary dated February 21, 2020,

which provide GLJ's reports on proved and probable reserves evaluations of Suncor's Canadian mining and in-situ leases that were evaluated as at December 31, 2019.

We hereby consent to being named and to the use of, reference to and excerpts and information derived from the said Reports by Suncor in its:

1. Annual Report on Form 40-F for the year ended December 31, 2019 (the "**Form 40-F**") and the incorporation by reference in the registration statements on Form S-8 (File No. 333-87604), Form S-8 (File No. 333-112234), Form S-8 (File No. 333-118648), Form S-8 (File No. 333-124415), Form S-8 (File No. 333-149532), Form S-8 (File No. 333-161021), Form S-8 (File No. 333-161029) and Form F-10 (File No. 333-225338) of Suncor, of our Reports;

2. Annual Report for the year ended December 31, 2019 (the "**Annual Report**") to be filed with the securities regulatory authorities of each of the provinces and territories of Canada; and

3. Annual Information Form dated February 26, 2020 (the "**AIF**"), which is incorporated by reference into the following prospectuses (collectively, the "**Prospectuses**"): (i) the short form base shelf prospectus of Suncor dated June 8, 2018 relating to the sale and issue of debt securities, common shares, preferred shares, subscription receipts, warrants, units, share purchase contracts and share purchase units from time to time in the aggregate amount of U.S. $3,000,000,000, and (ii) the short form base shelf prospectus of Suncor dated June 8, 2018 relating to the sale and issue of medium term notes, from time to time, in the aggregate principal amount of up to CDN $3,000,000,000.

We have read the Form 40-F, Annual Report, AIF and Prospectuses and have no reason to believe that there are any misrepresentations in the information contained therein that is derived from our Reports or that are within our knowledge as a result of the services which we performed in connection with the Reports.

Yours very truly,

GLJ PETROLEUM CONSULTANTS LTD.

"Tim R. Freeborn"

Tim R. Freeborn, P. Eng.
Vice-President and Chief Financial Officer

Dated: February 27, 2020
Calgary, Alberta, Canada

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EXHIBIT 99-5

Consent of GLJ Petroleum Consultants Ltd.
LETTER OF CONSENT

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EXHIBIT 99-6

Consent of Sproule Associates Limited and Sproule International Limited

LETTER OF CONSENT

TO: Suncor Energy Inc.
The Securities and Exchange Commission
The Securities Regulatory Authorities of Each of the Provinces and Territories of Canada

Dear Sirs/Mesdames:

Re: Suncor Energy Inc. ("Suncor")

We refer to the following reports (the "**Reports**") prepared by Sproule Associates Limited and Sproule International Limited:

- Evaluation of the P&NG Reserves of Suncor Energy Inc. in the Newfoundland Offshore Areas dated February 21, 2020;
- Evaluation of the P&NG Reserves of Suncor Energy Inc., Norway Properties dated February 21, 2020; and
- Evaluation of the P&NG Reserves of Suncor Energy Inc., UK Properties dated February 21, 2020,

which provide our reports on proved and probable reserves evaluations pursuant to Canadian disclosure requirements of Suncor's Canadian offshore conventional assets and international operations that were evaluated as at December 31, 2019.

We hereby consent to being named and to the use of, reference to and excerpts and information derived from the said Reports by Suncor in its:

1. Annual Report on Form 40-F for the year ended December 31, 2019 (the "**Form 40-F**") and the incorporation by reference in the registration statements on Form S-8 (File No. 333-87604), Form S-8 (File No. 333-112234), Form S-8 (File No. 333-118648), Form S-8 (File No. 333-124415), Form S-8 (File No. 333-149532), Form S-8 (File No. 333-161021), Form S-8 (File No. 333-161029) and Form F-10 (File No. 333-225338) of Suncor, of our Reports;

2. Annual Report for the year ended December 31, 2019 (the "**Annual Report**") to be filed with the securities regulatory authorities of each of the provinces and territories of Canada; and

3. Annual Information Form dated February 26, 2020 (the "**AIF**"), which is incorporated by reference into the following prospectuses (collectively, the "**Prospectuses**"): (i) the short form base shelf prospectus of Suncor dated June 8, 2018 relating to the sale and issue of debt securities, common shares, preferred shares, subscription receipts, warrants, units, share purchase contracts and share purchase units from time to time in the aggregate amount of U.S. $3,000,000,000, and (ii) the short form base shelf prospectus of Suncor dated June 8, 2018 relating to the sale and issue of medium term notes, from time to time, in the aggregate principal amount of up to CDN $3,000,000,000.

We have read the Form 40-F, Annual Report, AIF and Prospectuses and have no reason to believe that there are any misrepresentations in the information contained therein that is derived from our Reports or that are within our knowledge as a result of the services which we performed in connection with the Reports.

Sincerely,

SPROULE ASSOCIATES LIMITED AND SPROULE INTERNATIONAL LIMITED

"Cameron P. Six"

Cameron P. Six, P.Eng.
Chief Executive Officer

Dated: February 27, 2020
Calgary, Alberta, Canada

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EXHIBIT 99-6

Consent of Sproule Associates Limited and Sproule International Limited
LETTER OF CONSENT

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EXHIBIT 99-7

CERTIFICATION

I, Mark S. Little, certify that:

1. I have reviewed this annual report on Form 40-F of Suncor Energy Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

/s/ MARK S. LITTLE

Mark S. Little
President and Chief Executive Officer

DATE: February 27, 2020

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EXHIBIT 99-7

CERTIFICATION

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EXHIBIT 99-8

CERTIFICATION

I, Alister Cowan, certify that:

1. I have reviewed this annual report on Form 40-F of Suncor Energy Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

/s/ ALISTER COWAN

Alister Cowan
Chief Financial Officer

DATE: February 27, 2020

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EXHIBIT 99-8

CERTIFICATION

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EXHIBIT 99-9

**CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,
AS ENACTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the annual report of Suncor Energy Inc. (the "Company") on Form 40-F for the fiscal year ending December 31, 2019 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, MARK. S. LITTLE, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ MARK S. LITTLE

Mark S. Little
President and Chief Executive Officer
Suncor Energy Inc.

DATE: February 27, 2020

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EXHIBIT 99-9

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350, AS ENACTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

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EXHIBIT 99-10

**CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,
AS ENACTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the annual report of Suncor Energy Inc. (the "Company") on Form 40-F for the fiscal year ending December 31, 2019 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, ALISTER COWAN, Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ ALISTER COWAN

Alister Cowan
Chief Financial Officer
Suncor Energy Inc.

DATE: February 27, 2020

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EXHIBIT 99-10

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350, AS ENACTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

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Exhibit 99.11

Supplementary Oil and Gas Disclosures (unaudited)

The following disclosures are presented in accordance with United States Financial Accounting Standards Board ("FASB") Topic 932 — "Extractive Activities — Oil and Gas" and Subpart 1200 of Regulation S-K ("Subpart 1200") of the United States Securities and Exchange Commission. Disclosures pertaining to the audited consolidated financial statements as at and for the year ended December 31, 2019 (the "2019 Consolidated Financial Statements") of Suncor Energy Inc. ("Suncor" or the "company") were prepared in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board and Canadian generally accepted accounting principles contained within Part 1 of the Chartered Professional Accountants Canada Handbook, which differ in material respects from financial statements prepared in accordance with United States generally accepted accounting principles. The 2019 Consolidated Financial Statements are attached as Exhibit 99.1 to Suncor's annual report on Form 40-F for the year ended December 31, 2019 (the "Form 40-F").

Reserves Data

Reserves data included herein are estimates only and can be significantly impacted by a variety of internal and external factors. For more information on the risks involved when estimating reserves, see the discussion in the "Statement of Reserves Data and Other Oil and Gas Information — Significant Risk Factors and Uncertainties Affecting Reserves" section in Suncor's 2019 Annual Information Form (the "2019 AIF"), which is contained in the Form 40-F. Readers should also see Suncor's Management's Discussion and Analysis for the year ended December 31, 2019, which is attached as Exhibit 99.2 to the Form 40-F (the "2019 Management's Discussion and Analysis").

The reserves data presented herein, with an effective date of December 31, 2019, may differ in relation to the format and the basis from which volumes are economically determined under National Instrument 51-101 — "Standards of Disclosure for Oil and Gas Activities" ("NI 51-101"), as disclosed in the 2019 AIF. Subpart 1200 requires disclosure of net proved reserves, after royalties, using the average of the first-day-of-the-month prices for the twelve-month period prior to the end of the reporting period, whereas NI 51-101 requires disclosure of gross and net reserves, estimated using forecast prices and costs.

Net Proved Oil and Gas Reserves [(1)(2)]

The majority of Suncor's oil and gas reserves are in Canada. In order to align with the company's segmented information in the 2019 Consolidated Financial Statements, the 2019 Management's Discussion and Analysis and the 2019 AIF, the company presents the following supplementary oil and gas disclosures by showing amounts associated with its Oil Sands segment, which are exclusively in Canada and produce synthetic crude oil ("SCO") and bitumen, separate from other Canadian operations, which are aggregated with Suncor's international operations (collectively, "Exploration and Production") and produce crude oil, natural gas and natural gas liquids ("NGLs"). Exploration and Production reserves are in offshore Canada, offshore UK, and offshore Norway.

At December 31, (net reserves, constant prices and costs)	SCO (mmbbls)		Bitumen (mmbbls)		Crude Oil[3] (mmbbls)		Natural Gas (bcf)		Total (mmboe)	
	2019	2018	2019	2018	2019	2018	2019	2018	2019	2018
Proved Developed										
Oil Sands	2,032	2,183	951	1,003	—	—	—	—	2,984	3,186
Exploration and Production	—	—	—	—	110	91	1	1	111	91
	2,032	2,183	951	1,003	110	91	1	1	3,094	3,277
Proved Undeveloped										
Oil Sands	542	522	581	602	—	—	—	—	1,123	1,123
Exploration and Production	—	—	—	—	49	67	9	10	51	69
	542	522	581	602	49	67	9	10	1,173	1,193
Proved										
Oil Sands	2,574	2,704	1,532	1,605	—	—	—	—	4,106	4,309
Exploration and Production	—	—	—	—	160	158	11	11	161	160
	2,574	2,704	1,532	1,605	160	158	11	11	4,267	4,469

Reconciliation of Net Proved Oil and Gas Reserves

(net reserves, constant prices and costs)	Balance at December 31 2017	Revisions of Previous Estimates[4]	Improved Recovery	Acquisitions	Extensions and Discoveries[5]	Production	Dispositions[6]	Balance at December 31 2018
Oil Sands								
SCO (mmbbls)	2,737	52	—	71		(156)	—	2,704
Bitumen	1,640	12	—	18		(65)	—	1,605
Exploration and Production								—
Crude oil[3] (mmbbls)	140	16	—	7	27	(33)	—	158
Natural gas (bcf)	6	1	—	10	—	(3)	(3)	11
Total (mmboe)	4,519	80	—	98	28	(254)	(1)	4,469

(net reserves, constant prices and costs)	Balance at December 31 2018	Revisions of Previous Estimates[4]	Improved Recovery	Acquisitions	Extensions and Discoveries[5]	Production	Dispositions	Balance at December 31 2019
Oil Sands								
SCO (mmbbls)	2,704	33	—	—	—	(164)	—	2,574
Bitumen	1,605	(6)	2	—	—	(68)	—	1,532
Exploration and Production								
Crude oil[3] (mmbbls)	158	30	1	—	5	(35)	—	160
Natural gas (bcf)	11	1	—	—	1	(2)	—	11
Total (mmboe)	4,469	57	2	—	5	(267)	—	4,267

Notes to Reserves Data:

(1) Definitions

a. Net reserves, in relation to Suncor's production and reserves, represents the company's working interest share after deduction of royalty obligations, plus the company's royalty interests in production and reserves.

b. Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty (at least a 90% probability that the quantities actually recovered will equal or exceed the estimate) to be economically producible, from a given date forward, from known reservoirs, and under existing economic conditions, operating methods and government regulations.

c. Proved developed oil and gas reserves are those quantities that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and can be expected to be recovered through extraction equipment and infrastructure installed and operational at the time of the reserves estimate for projects that extract oil and gas by means not involving a well.

d. Proved undeveloped oil and gas reserves are those quantities that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

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

(3) Natural gas liquids reserves are not significant and have been presented in combination with crude oil reserves.

(4) Revisions of previous estimates include changes to proved reserves, resulting from new information (except for an increase in proved acreage) normally obtained from development drilling and production history or resulting from a change in economic factors, such as changes in constant prices used for the reserve evaluation.

(5) Extensions and discoveries are additions to proved reserves from proved acreage of previously discovered reservoirs through additional drilling in periods subsequent to discovery or discovery of new fields with proved reserves or of new reservoirs of proved reserves in old fields.

(6) Dispositions are reductions in reserves estimates as a result of selling all or a portion of an interest in oil and gas properties. During 2018, the company disposed of its northeast B.C. mineral landholdings, including associated production.

Capitalized Costs

	At December 31, 2019			At December 31, 2018		
($ millions)	Oil Sands	Exploration and Production	Total	Oil Sands	Exploration and Production	Total
Exploration and evaluation assets [1]	2,178	250	2,428	2,100	219	2,319
Oil and gas properties [2][3]	18,795	21,801	40,596	17,083	20,763	37,846
Plant and equipment [2][3]	66,451	1,074	67,525	63,213	1,104	64,317
— accumulated provision [2]	(30,581)	(15,298)	(45,879)	(22,654)	(14,075)	(36,729)
Total	56,843	7,827	64,670	59,742	8,011	67,753

(1) Exploration and evaluation assets largely represent amounts associated with unproved properties, but may include properties with proved reserves for which Suncor's Board of Directors have not sanctioned development. See note 17 of the 2019 Consolidated Financial Statements.

(2) Oil and Gas Properties, Plant and Equipment and the accumulated provision largely represent amounts associated with proved properties. See note 15 of the 2019 Consolidated Financial Statements. Includes amounts capitalized to Property, Plant and Equipment on the Consolidated Balance Sheets of the 2019 Consolidated Financial Statements that relate to the company's right-of-use assets under IFRS 16. See note 16 of the 2019 Consolidated Financial Statements.

(3) Includes amounts capitalized to Property, Plant and Equipment on the Consolidated Balance Sheets of the 2019 Consolidated Financial Statements that relate to the company's decommissioning and restoration activities.

Costs Incurred for Property Acquisition, Exploration and Development Activities

	Year ended December 31, 2019			Year ended December 31, 2018		
($ millions)	Oil Sands	Exploration and Production	Total	Oil Sands	Exploration and Production	Total
Unproved property acquisition	—	—	—	—	32	32
Proved property acquisition	—	—	—	1,143	82	1,225
Exploration [1]	204	248	452	73	179	252
Development [2]	3,580	992	4,572	3,398	800	4,198
Total	3,784	1,240	5,024	4,614	1,093	5,707

(1) Includes amounts capitalized to Exploration and Evaluation on the Consolidated Balance Sheets as well as those charged to Exploration Expense on the Consolidated Statements of Comprehensive Income, of the 2019 Consolidated Financial Statements.

(2) Includes amounts capitalized to Property, Plant and Equipment on the Consolidated Balance Sheets of the 2019 Consolidated Financial Statements that relate to the company's decommissioning and restoration activities.

Results of Operations for Oil and Gas Producing Activities[1][2]

($ millions)	Year ended December 31, 2019			Year ended December 31, 2018		
	Oil Sands	Exploration and Production	Total	Oil Sands	Exploration and Production	Total
Operating revenues, net of royalties	17,430	3,070	20,500	15,345	3,217	18,562
Other income (loss)	172	430	602	387	(68)	319
	17,602	3,500	21,102	15,732	3,149	18,881
Purchases of crude oil and products	1,407	—	1,407	1,563	—	1,563
Operating, selling and general	8,027	525	8,552	7,577	507	8,084
Transportation	1,293	80	1,373	1,144	85	1,229
Depreciation, depletion, amortization and impairment	8,170	1,505	9,675	4,024	967	4,991
Exploration	127	129	256	44	78	122
(Gain) loss on disposal of assets	(14)	(228)	(242)	(108)	91	(17)
Finance expenses	318	73	391	320	46	366
(Loss) earnings before income taxes	(1,726)	1,416	(310)	1,168	1,375	2,543
Income taxes — (recovery) expense	(1,299)	411	(888)	223	568	791
Net (loss) earnings	(427)	1,005	578	945	807	1,752

(1) Beginning in 2019, results from the company's Energy Trading business are included within each of the respective operating business segments to which the respective trading activity relates. The Energy Trading business was previously reported within the Corporate, Energy Trading and Eliminations segment. Prior periods have been restated to reflect this change.

(2) The company adopted IFRS 16 on January 1, 2019 using the modified retrospective transition approach and, therefore, prior periods have not been restated. See note 5 of the 2019 Consolidated Financial Statements for further information.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

The standardized measure of discounted future net cash flows relating to Suncor's proved oil and gas reserves are calculated in accordance with FASB Topic 932 — "Extractive Activities — Oil and Gas". Future cash inflows are estimated using the trailing twelve-month average price, which are also used in estimating the entity's proved oil and gas reserves. Future development and production costs, including the associated decommissioning and restoration activities, are calculated by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. The appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, were applied to the future pretax net cash flows, less the tax basis of the properties involved. A prescribed rate of 10% is applied to discount the future net cash flows.

The calculation of the standardized measure of discounted future net cash flows is based upon information prepared by the company's independent qualified reserves evaluators (which includes decommissioning and restoration activities), and adjusted for future income taxes.

It should not be assumed that the estimates of future net cash flows presented in the tables below represent the fair market value of the reserves. There is no assurance that the price and cost assumptions will be attained and variances could be material. Future changes to income tax, royalty and environmental regulations could also have a significant impact on the respective assumptions. There is no guarantee that the estimates for SCO, bitumen, crude oil, and natural gas reserves provided herein will be recovered. Actual SCO, bitumen, crude oil, and natural gas reserves may be greater than or less than the estimates provided herein.

The following twelve-month average prices were used to calculate the standardized measure of discounted future net cash flows:

Year	Brent North Sea	WTI Cushing Oklahoma	WCS Hardisty Alberta	Light Sweet Edmonton Alberta	Pentanes Plus Edmonton Alberta	AECO Gas	National Balancing Point North Sea
	US$/bbl	US$/bbl	Cdn$/bbl	Cdn$/bbl	Cdn$/bbl	Cdn$/mmbtu	Cdn$/mmbtu
2019	63.15	55.69	57.22	67.66	68.70	1.66	6.69
2018	71.54	65.56	50.44	70.07	79.39	1.46	10.03

	At December 31, 2019			At December 31, 2018		
($ millions)	Oil Sands	Exploration and Production	Total	Oil Sands	Exploration and Production	Total
Future cash inflows	251,040	13,218	264,258	247,927	14,259	262,186
Future production costs	(145,374)	(3,960)	(149,334)	(132,241)	(3,446)	(135,687)
Future development costs	(52,917)	(3,287)	(56,204)	(56,071)	(3,175)	(59,246)
Future income tax expenses	(10,716)	(1,764)	(12,480)	(14,491)	(1,988)	(16,479)
Future net cash flows	42,033	4,207	46,240	45,124	5,650	50,774
10% Discount Factor	(22,655)	(308)	(22,963)	(23,280)	(1,227)	(24,507)
Standardized measure of discounted future net cash flows	19,378	3,899	23,277	21,844	4,423	26,267

Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

($ millions)	2019	2018
Standardized measure of discounted future net cash flows — beginning of year	26,267	21,831
Sales and transfers of oil and gas produced	(8,005)	(6,998)
Net changes in sales prices and operating costs related to future production	(5,673)	6,277
Net change due to extensions, discoveries and improved recovery	2,632	3,923
Net change due to acquisition and dispositions	—	1,228
Net change due to revisions in quantity estimates	(834)	1,630
Previously estimated development costs incurred during the period	4,077	3,805
Changes in estimated future development costs	(314)	(6,010)
Accretion of discount	2,773	2,210
Net change in income taxes	2,353	(1,629)
Standardized measure of discounted future net cash flows — end of year	23,277	26,267

QuickLinks

Exhibit 99.11