UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 40-F

(Check One)

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

or

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

For fiscal year ended: December 31, 2021
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:

☒ Annual Information Form ☒ 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, 2021 there were 1,441,250,800 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☒ No☐

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☒ No☐

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 ☐

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.

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☒

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 23, 2022, Audited Consolidated Financial Statements, Management's Discussion and Analysis for the year ended December 31, 2021 and Supplementary Oil and Gas Disclosures, included as Exhibit 99-1, Exhibit 99-2, Exhibit 99-3 and Exhibit 99-9, 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- 238618).

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 2 and 3 of Exhibit 99-2 and page 66 of Exhibit 99-3.

ATTESTATION REPORT OF THE REGISTERED PUBLIC ACCOUNTING FIRM

See pages 4, 5 and 6 of Exhibit 99-2.

AUDIT COMMITTEE FINANCIAL EXPERT

See page 117 of Exhibit 99-1.

CODE OF ETHICS

See pages 40, 41 and 42 of Exhibit 99-1.

FEES PAID TO PRINCIPAL ACCOUNTANT

See page 118 of Exhibit 99-1.

AUDIT COMMITTEE PRE-APPROVAL POLICIES

See Schedule "B" of Exhibit 99-1.

APPROVAL OF NON-AUDIT SERVICES

See Schedule "B" of Exhibit 99-1.

IDENTIFICATION OF THE AUDIT COMMITTEE

See page 116 of Exhibit 99-1.

EXHIBIT INDEX

Exhibit No.	Description
99-1	Annual Information Form of Suncor Energy Inc. for the fiscal year ended December 31, 2021 dated February 23, 2022
99-2	Audited Consolidated Financial Statements of Suncor Energy Inc. for the fiscal year ended December 31, 2021
99-3	Management's Discussion and Analysis for the fiscal year ended December 31, 2021, dated February 23, 2022
99-4	Consent of KPMG LLP
99-5	Consent of GLJ Ltd.
99-6	Certificate of the Chief Executive Officer Pursuant to Exchange Act Rules 13a-14(a) or 15d-14(a)
99-7	Certificate of the Chief Financial Officer Pursuant to Exchange Act Rules 13a-14(a) or 15d-14(a)
99-8	Certificate of the Chief Executive Officer Pursuant to 18 U.S.C. Section 1350, as Enacted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
99-9	Certificate of the Chief Financial Officer Pursuant to 18 U.S.C. Section 1350, as Enacted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
99-10	Supplementary Oil and Gas Disclosures
101	Inline interactive data file
104	Cover page interactive data file (formatted as Inline XBRL and contained in Exhibit 101)

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 24, 2022

PER: /s/ ALISTER COWAN
Alister Cowan
Chief Financial Officer

Exhibit 99.1

ANNUAL INFORMATION FORM DATED FEBRUARY 23, 2022

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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 29 of the company’s 2021 audited Consolidated Financial Statements), unless the context otherwise requires. Suncor Energy Inc. has numerous direct and indirect subsidiaries, partnerships and joint arrangements (“affiliates”), which own and operate assets and conduct activities in different jurisdictions. The terms “Suncor” or “the company” in this AIF are used herein for simplicity of communication and only mean that there is an affiliation with Suncor Energy Inc., without necessarily identifying the specific nature of the affiliation. The use of such terms in any statement herein does not mean that they apply to Suncor Energy Inc. or any particular affiliate, and does not waive the corporate separateness of any affiliate. For further clarity, Suncor Energy Inc. does not directly operate or own assets in the U.S. 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 2021 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, 2021. References to the MD&A mean Suncor’s Management’s Discussion and Analysis, dated February 23, 2022.

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.

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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 a lower sulphur content is referred to as **sweet synthetic crude oil**, while SCO with a 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, it 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 their 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 to support production in an existing field, such as observation wells or wells drilled for the purpose of injecting gas, steam or water.

Sidetrack wells are drilled from existing wells. Operations start first by abandoning the lateral section of an existing well and subsequently drilling and completing a new lateral section. The sidetracked well is then tied it to the existing wellhead and uses the existing surface facilities.

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 blended 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 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 refers to a froth treatment process whereby a lighter diluent or solvent that contains paraffin is used to selectively remove some of the asphaltenes (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 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 production sharing contract, 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. 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 is a metric used to quantify the cubic metres of water (converted to steam) required to produce one cubic metre of oil. Different reservoirs have different steam-to-oil ratios primarily due to differences in reservoir characteristics like oil viscosity, thickness, and permeability, but within similar reservoir characteristics, the ratio is a good measure of thermal efficiency. 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 content 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.

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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
NO_2	nitrogen dioxide
NOx	nitrogen oxides
SO_2	sulphur dioxide
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 – 6 th Avenue S.W., Calgary, Alberta, T2P 3E3.

Intercorporate Relationships

Suncor's material subsidiaries, each of which is wholly owned, either directly or indirectly, by the company as at December 31, 2021, 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 natural gas for its upstream and downstream business, and procures crude oil feedstock and markets natural gas liquids (NGLs) and liquefied petroleum gas (LPG) for its downstream business.
Suncor Energy Ventures Corporation	Alberta	A subsidiary that indirectly owns a 36.74% ownership in the Syncrude joint operation.
Suncor Energy Ventures Partnership	Alberta	A subsidiary that 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, 2021, and (ii) less than 10% of the company's consolidated revenues for the fiscal year ended December 31, 2021. In aggregate, the remaining subsidiaries accounted for less than 20% of the company's consolidated assets as at December 31, 2021, and less than 20% of the company's consolidated revenues for the fiscal year ended December 31, 2021.

GENERAL DEVELOPMENT OF THE BUSINESS

Overview

Suncor is an integrated energy company headquartered in Calgary, Alberta, Canada. Suncor's operations include oil sands development, production and upgrading; offshore oil and gas; petroleum refining in Canada and the U.S.; and the company's Petro-Canada retail and wholesale distribution networks (including Canada's Electric Highway™, a coast-to-coast network of fast-charging electric vehicle stations). Suncor is developing petroleum resources while advancing the transition to a low-emissions future through investment in power, renewable fuels and hydrogen. Suncor also conducts energy trading activities focused principally on the marketing and trading of crude oil, natural gas, byproducts, refined products and power. Suncor has been recognized for its performance and transparent reporting on the Dow Jones Sustainability index, FTSE4Good and CDP. Suncor is also listed on the UN Global Compact 100 stock index. Suncor's common shares (symbol: SU) are listed on the TSX and NYSE.

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, produces bitumen from mining and in situ operations. Bitumen is either upgraded into SCO for refinery feedstock and diesel fuel, or blended with diluent for refinery feedstock or direct sale to market through the company's midstream infrastructure and its marketing activities. The segment includes the marketing, supply, transportation and risk management of crude oil, natural gas, power and byproducts. 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 and the interconnecting pipelines between Suncor's Oil Sands Base operations and Syncrude.
    - **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 that may support future in situ production, including Meadow Creek (75%), Lewis (100%), OSLO (77.78%), Gregoire (100%), 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 the Fort Hills mining and extraction operation, 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 oil sands mining and upgrading operation, which the company operates. Suncor assumed the role of operator of the Syncrude joint operation on September 30, 2021.

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, the Norwegian Sea and the Norwegian North Sea, and onshore assets in Libya and Syria. This segment also includes the marketing and risk management of crude oil and natural gas.

- **E&P Canada** operations include Suncor's 48% working interest in Terra Nova, which Suncor operates. Production at Terra Nova has been shut in since the fourth quarter of 2019. In the third quarter of 2021, a new ownership agreement was finalized that increased Suncor's working interest from 37.675% to 48%, and a decision was made to move forward with the Asset Life Extension (ALE) Project. The company is anticipating a safe and reliable return to operations before the end of 2022. Suncor also holds non-operated interests in Hibernia (20% in the base project and 19.485% in the Hibernia Southern Extension Unit), White Rose (27.5% in the base project and 26.125% in the extensions), and Hebron (21.034%). Suncor increased its non-operated interest in the Hibernia Southern Extension Unit from 19.19% in 2020 to 19.485% in 2021 through redetermination. In 2021, Suncor entered into a conditional agreement to increase its interest in the White Rose assets by 12.5% to approximately 40% on a go-forward basis, subject to a number of conditions including an economic restart decision by the operator on the West White Rose Project by mid-2022. In addition, the company holds interests in several exploration licences and significant discovery licences offshore Newfoundland and Labrador.

- **E&P International** operations include Suncor's non-operated interests in Buzzard (29.89%), Oda (30%), the Fenja Project (17.5%) and the Rosebank future development project (40%). In the fourth quarter of 2021, Suncor sold its 26.69% working interest in the Golden Eagle Area Development located in the U.K. sector of the North Sea. Buzzard 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. Production in Libya was steady in 2021, albeit at reduced rates. The timing of a return to normal operations in Libya remains uncertain due to continued political unrest. Suncor also owns, pursuant to a production sharing contract, 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, supply and risk management of refined products, crude oil, natural gas, power and byproducts. This segment also includes the trading of crude oil, refined products, natural gas and power.

- **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 mbbls/d refinery located in Montreal, Quebec, and an 85 mbbls/d refinery located in Sarnia, Ontario.

    - **Western North America** operations include a 146 mbbls/d refinery located in Edmonton, Alberta, and 98 mbbls/d refinery in Commerce City, Colorado, that is comprised of three plants at two refineries. For simplicity, Suncor refers to this as the Commerce City refinery.

  - 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 customers primarily through a combination of company-owned Petro-Canada™ locations, branded-dealers in Canada and company-owned locations in the U.S. marketed under other international brands. This includes Canada's Electric Highway™, a coast-to-coast network of fast-charging electric vehicle stations. The company's marketing operations also sells refined petroleum products through a nationwide commercial road transportation network in Canada, and to other commercial and industrial customers, including other retail sellers, in Canada and the U.S.

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 Forty Mile Wind Power Project, which was restarted in early 2021 and is currently planned for completion in late 2022.

- **Corporate** activities include stewardship of Suncor's debt and borrowing costs, expenses not allocated to the company's businesses, and investments in clean technology, such as Suncor's investment in Enerkem Inc., LanzaJet, Inc., Svante Inc. and the Varennes Carbon Recycling facility.

- Intersegment revenues and expenses are removed from consolidated results in **Eliminations**. Intersegment activity includes the sale of product between the company's segments, primarily relating 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.

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 2020; however, the program was suspended in December 2020 and expired on December 31, 2021. Production curtailment primarily affected the company's non-upgraded bitumen production as the company maximized the production of higher-value SCO barrels during the time the program was in effect.

- **First oil from Oda.** First oil was achieved ahead of schedule at Oda on March 16, 2019.

- **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.

- **Sale of equity interest in Canbriam.** In June 2019, Suncor completed the sale of its 37% equity interest in Canbriam Energy Inc. 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.

- **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 a project to replace its coke-fired boilers with a new cogeneration facility at Oil Sands Base. The project is expected to provide reliable steam generation required for Suncor's extraction and upgrading operations and reduce the greenhouse gas (GHG) emissions intensity associated with steam production at Oil Sands Base operations by approximately 25%. In addition, the excess 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 GHG emissions in the province of Alberta by approximately 5.1 Mt per year. The project is estimated to cost approximately $1.4 billion with an expected in-service date between 2024 and 2025.

- **Continued investment in clean energy.** In the fourth quarter of 2019, Suncor sanctioned the Forty Mile Wind Power Project in southern Alberta, which was restarted in early 2021 after it was temporarily paused during 2020. The project is currently planned for completion in late 2022. 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 entered into a strategic alliance with Microsoft. This alliance enables Suncor to use 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 stations.** Suncor advanced its sustainability and technology initiatives by completing Canada's Electric Highway™, a coast-to-coast network of fast-charging electric vehicle stations across Canada, during the fourth quarter of 2019.

- **Continuation of share repurchases.** In May 2019, Suncor renewed its normal course issuer bid (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 to 78,549,178 common shares between May 6, 2019, and May 5, 2020. 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.

2020

- **The COVID-19 pandemic.** On January 30, 2020, the World Health Organization declared the Coronavirus disease (COVID-19) outbreak a Public Health Emergency of International Concern and, on March 10, 2020, declared it to be a pandemic. The impacts of COVID-19 resulted in significant disruptions to the company's business operations and a significant

increase in economic uncertainty, with fluctuating demand for commodities contributing to volatile prices.

- **Debt issuance and enhanced liquidity.** To help strengthen the financial resiliency of the company, Suncor secured $2.8 billion in additional credit facilities (which were subsequently cancelled in the first quarter of 2021) and issued $1.25 billion of 5.00% senior 10-year unsecured medium-term notes, US$450 million of 2.80% senior three-year unsecured notes and US$550 million of 3.10% senior five-year unsecured notes in 2020.

- **Share repurchases.** During the first quarter of 2020, the company repurchased 7.5 million of the company's common shares for cancellation at an average price of $40.83 per common share, for a total repurchase cost of $307 million. Subsequently, in response to the impacts of the COVID-19 pandemic, the company elected to suspend share repurchases and decided not to renew its NCIB.

- **Dividend reduction.** In response to the uncertainty created by the COVID-19 pandemic, in the second quarter of 2020, the Board approved a reduction in the company's quarterly dividend to $0.21 per common share from $0.465 per common share.

- **Continuing investment in global energy expansion.** During the second quarter of 2020, Suncor made an equity investment in LanzaJet, Inc., a company that is working to bring sustainable aviation fuel and renewable diesel to the commercial market. In addition, in the fourth quarter of 2020, Suncor, Enerkem Inc. and other partners announced plans for the construction of a biorefinery in Varennes, Quebec. The Varennes Carbon Recycling facility is designed to convert non-recyclable commercial and industrial waste, as well as forestry waste, to biofuels and renewable chemicals. These strategic investments, together with the equity investment in Enerkem Inc. in 2019, complement Suncor's existing product mix and demonstrate Suncor's involvement in the evolving global energy expansion.

- **Temporary transition to one-train operation at Fort Hills.** During the second quarter of 2020, in response to the impacts of the COVID-19 pandemic, the Fort Hills partners agreed to temporarily reduce Fort Hills from operating two primary extraction trains to a one-train operation.

- **Deployment of autonomous haulage systems at Fort Hills.** The company deployed autonomous haulage systems at its Fort Hills mine in 2020. 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.

- **Execution of Firebag debottlenecking activities.** Suncor accelerated maintenance at Firebag, which allowed the company to integrate and fully utilize additional steam and water treatment assets. The maintenance was completed in the fourth quarter of 2020 and the nameplate capacity of the facilities increased from 203 mbbls/d to 215 mbbls/d of bitumen.

- **Deferral of Terra Nova ALE Project.** On May 3, 2019, the company sanctioned the Terra Nova ALE Project to extend the life of Terra Nova by approximately 10 years. This project was originally planned for execution by the end of 2020. Given the economic environment that developed as a result of the COVID-19 pandemic, the company deferred the project until an economically viable path forward with a safe and reliable return to operations could be determined.

- **Interconnecting pipelines between Suncor's Oil Sands Base and Syncrude .** The interconnecting pipelines, which connect Syncrude's Mildred Lake site and Suncor's Oil Sands Base operations, enhance integration between these assets and provide increased

operational flexibility through the ability to transfer bitumen and sour SCO between the two plants, enabling higher upgrader utilization. The asset was brought into service and transfers began in December 2020, reflecting the enhanced integration and operational flexibility between these assets.

- **West White Rose Project placed in safe mode.** The operator of the project announced a full project review given the continued market uncertainty as a result of the COVID-19 pandemic, along with the cancellation of the 2021 construction season and moved the project into safekeeping mode.

- **Suncor to assume operatorship of Syncrude.** In the fourth quarter of 2020, the Syncrude joint venture owners reached an agreement in principle for Suncor to take over as operator of the Syncrude joint operation by the end of 2021. Suncor assumed the role of operator on September 30, 2021.

- **Workforce reductions and downstream restructuring.** In the fourth quarter of 2020, Suncor announced that it would be making workforce reductions of 10% to 15% of employees by mid-2022 as part of the company's steps to achieve its incremental free funds flow target. Furthermore, Suncor announced its decision to relocate the company's downstream offices in Mississauga and Oakville, Ontario, to Calgary, Alberta.

2021

- **Restart of share repurchases.** On February 3, 2021, the TSX accepted a notice filed by Suncor to commence a new NCIB to purchase and cancel up to 44,000,000 of the company's common shares beginning on February 8, 2021, and ending February 7, 2022, through the facilities of the TSX, NYSE and/or alternative trading platforms.

- **Investment in carbon capture.** During the first quarter of 2021, Suncor announced an equity investment in Svante Inc., a Canadian carbon capture company. With support from Suncor and other companies, Svante plans to continue developing its technology to capture CO_2 from industrial processes at reduced costs. Carbon capture is a strategic technology area for Suncor to reduce GHG emissions in Suncor's base business and produce blue hydrogen as an energy product.

- **Debt reduction.** During the first quarter of 2021, consistent with its debt management and reduction strategy, Suncor cancelled $2.8 billion in bi-lateral credit facilities that were no longer required, as they were entered into in March and April of 2020 to ensure access to adequate financial resources in connection with the COVID-19 pandemic. In addition, Suncor also exercised the early redemption options on its outstanding US$220 million of 9.40% senior unsecured notes and $750 million 3.10% medium-term notes, both due in 2021. During the first quarter of 2021, the company also issued US$750 million of 3.75% senior unsecured notes and $500 million of 3.95% senior unsecured medium-term notes, both due on March 4, 2051.

- **Updated strategy focused on shareholder returns and GHG emissions reductions.** On Suncor's Investor Day on May 26, 2021, Suncor outlined the company's medium-term outlook for structural cost reductions, a stronger balance sheet, improved margin capture and a sustainable increase of cash returns to shareholders while strengthening the company's environmental performance. In addition, the strategy included the goal for Suncor to become a net-zero GHG emissions company by 2050 (on emissions produced from running its facilities, including those in which it has a working interest) and to substantially contribute to society's net-zero ambitions. While Suncor will continue to track and report emissions intensity, the company has set a more ambitious near-term goal to better align with its objective to reach net-zero emissions and to provide a clearer way to demonstrate progress by targeting annual emissions reductions of 10 megatonnes across its value chain by 2030.

- **Oil Sands Pathways to Net Zero Alliance.** Suncor, together with Canadian Natural Resources Limited, Cenovus Energy Inc., Imperial Oil Resources Limited and MEG Energy Corp. –who together operate 90% of oil sands production – announced the Oil Sands Pathways to Net Zero alliance, which was expanded to include ConocoPhillips Canada Resources Corp. in November 2021. The goal of this alliance is to work collectively with the federal and Alberta governments to achieve net-zero GHG emissions from oil sands operations by 2050. The Pathways initiative will explore several parallel pathways to address GHG emissions, including the creation of a Carbon Capture, Utilization and Storage trunkline connected to a carbon sequestration hub to enable multi-sector 'tie-in' projects as well as the implementation of other next-generation technologies.

- **Completed sale of the Golden Eagle Area Development.** In the fourth quarter of 2021, the company completed the sale of its 26.69% working interest in the Golden Eagle Area Development for gross proceeds of US$250 million net of closing adjustments and other closing costs, in addition to future contingent consideration of up to US$50 million. The effective date of the sale was January 1, 2021.

- **Suncor assumes operatorship of Syncrude.** Suncor assumed the role of operator of the Syncrude joint operation on September 30, 2021, a critical step towards driving greater integration, efficiencies and competitiveness across all Suncor-operated assets in the region.

- **Terra Nova ALE Project moving forward.** Suncor and the co-owners of the Terra Nova project finalized an agreement to restructure the project ownership and move forward with the ALE Project, which is expected to extend production life by approximately 10 years. As a result of the agreement, Suncor increased its ownership in the project by approximately 10% to 48%. The Terra Nova Floating, Production, Storage and Offloading facility is dry docked in Spain undergoing maintenance work and is expected to sail back to Canada and return to operations before the end of 2022.

- **Conditional agreement reached to increase interest in the West White Rose Project.** Suncor entered into a conditional agreement to increase its interest in the White Rose assets subject to a number of conditions including an economic restart decision for the West White Rose Project by mid-2022. Should the conditions be met, Suncor has agreed to increase its ownership interest in the White Rose assets by 12.5% to approximately 40% in exchange for a cash payment by the operator to Suncor.

- **First oil achieved at Buzzard Phase 2.** Buzzard Phase 2, which will extend production life of the existing Buzzard field, achieved first oil in the fourth quarter of 2021. Buzzard Phase 2 is expected to reach its peak production in 2022, adding approximately 12,000 boe/d gross (approximately 3,500 boe/d net to Suncor) to existing Buzzard production.

- **Historic partnership with Indigenous communities.** Suncor, together with eight Indigenous communities, acquired a 15% equity interest in the Northern Courier Pipeline in the fourth quarter of 2021. The Northern Courier Pipeline, which connects the Fort Hills asset to Suncor's East Tank Farm, is now operated by Suncor and is expected to provide the eight Indigenous communities with reliable income for decades.

- **Dividend increase and acceleration of the share repurchase program.** In the fourth quarter of 2021, the Board approved a quarterly dividend of $0.42 per share, reinstating the quarterly dividend to 2019 levels. The Board also approved an increase to the company's share repurchase program to approximately 7% of Suncor's public float as at January 31, 2021, and concurrently, the TSX accepted a notice to increase the maximum number of common shares the company may repurchase pursuant to its NCIB to 7% of the company's public float.

- **Continuation of share repurchases.** Since the start of its NCIB in February 2021, the company repurchased approximately 84 million of its common shares at an average price of $27.45 per common share, or the equivalent of 5.5% of Suncor's public float as at January 31, 2021. Subsequent to the fourth quarter of 2021, the Board approved a renewal of the company's NCIB for the repurchase of approximately 5% of Suncor's issued and outstanding common shares as at January 31, 2022, over a twelve-month period, and concurrently, the TSX accepted a notice filed by Suncor to renew its NCIB in respect of the repurchase of such shares.

- **Continued debt reduction.** Subsequent to the fourth quarter of 2021, the company completed an early redemption of its outstanding US$182 million 4.50% notes, originally scheduled to mature in the second quarter of 2022.

- **Fort Hills resumed operation of second primary extraction train.** Fort Hills resumed two-train operations late in the fourth quarter of 2021. The company is on track to operate the Fort Hills asset at average utilization rates of 90% throughout 2022.

- **Increased investment in Varennes Carbon Recycling facility.** In the fourth quarter of 2021, Suncor increased its equity interest in the facility, which Suncor expects will complement its existing biofuels business.

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.

- **Transportation**

Suncor has regional pipelines which connect the company's mining, in situ, upgrading and storage assets, providing optionality and improving upgrader utilization and optimization of bitumen value for Suncor.

Additionally, interconnecting pipelines connect Syncrude's Mildred Lake site and Suncor's Oil Sands Base operations. The pipelines provide increased operational flexibility through the ability to transfer bitumen and sour SCO between the two plants, enabling higher upgrader utilization. The pipelines create flexibility for Syncrude to sell intermediate products to Suncor, which include bitumen and sour SCO.

- **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 revegetation.

Oil sands tailings are the remaining sand, water, clay, silt and residual hydrocarbons left after most 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. 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 2021, the company mined approximately 150.8 million tonnes of bitumen ore (2020 – 145.9 million tonnes) and processed an average of 276.2 mbbls/d of mined bitumen in its extraction facilities (2020 – 262.2 mbbls/d).

The company filed a regulatory application in the first quarter of 2020 to potentially replace Suncor's Millennium and North Steepbank mines as they reach the end of their useful lives after 2030. The application does not represent a project sanction and a final sanctioning is expected later in the decade.

Upgrading Facilities

Suncor's upgrading facilities consist of two upgraders: Upgrader 1, which has a capacity of approximately 110 mbbls/d of SCO, and Upgrader 2, which has a 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.

Suncor is proceeding with its project to replace the existing coke-fired boilers at Oil Sands Base with a new 800 MW cogeneration facility. 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 excess 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 GHG emissions in the province of Alberta by approximately 5.1 Mt per year. The project is estimated to cost approximately $1.4 billion with an expected in-service date between 2024 and 2025.

During 2021, Suncor's Oil Sands Base assets averaged 313.7 mbbls/d of upgraded (SCO and diesel) production, mainly sourced from bitumen provided by both Oil Sands Base and In Situ operations, including the company's internal consumption and transfers through the interconnecting pipelines (2020 –311.8 mbbls/d). In the 2021 AIF, the company revised the presentation of current and prior year upgraded Oil Sands Base production to include internally consumed diesel volumes and transfers through the interconnecting pipelines with Syncrude.

Other Mining Leases

Suncor, directly and indirectly, owns interests in several other mineable oil sands leases, including Base Mine Extension 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 Base Mine Extension 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, that 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 215 mbbls/d of bitumen. 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, 2021, Firebag had 20 well pads in operation, with 265 SAGD well pairs and 52 infill wells either producing or on initial steam injection. Central processing facilities have been designed to provide some flexibility 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 122 MW and, in 2021, Firebag exported approximately 271 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 2021, Firebag production averaged 206.4 mbbls/d of bitumen (2020 – 182.4 mbbls/d) with a steam-to-oil ratio of 2.6 (2020 – 2.7). After completing maintenance and debottlenecking activities to expand the capacity of the facility in late 2020, Firebag operated near nameplate capacity of 215 mbbls/d in 2021.

Suncor is working on developing incremental debottlenecks to maximize the value of the Firebag asset. Debottlenecking capacity and timing will depend on economic conditions, and can be supported by integrated well pad development and solvent SAGD technologies.

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, 2021, MacKay River included nine well pads with 131 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 2021, MacKay River production averaged 35.9 mbbls/d of bitumen (2020 – 16.7 mbbls/d) with a steam-to-oil ratio of 2.8 (2020 – 3.6). MacKay River operated at near nameplate capacity of 38 mbbls/d throughout 2021.

Other In Situ Leases

Suncor owns and operates several other oil sands leases that may support future in situ production, including Lewis, Meadow Creek, Gregoire, OSLO, Chard and Kirby. Suncor holds a 100% working interest in Lewis and Gregoire, a 75% working interest in Meadow Creek, a 77.78% working interest in OSLO, interests varying from 25% to 50% in Chard, and a 10% non-operated interest in Kirby.

Suncor is the operator of Meadow Creek, which is located approximately 40 kilometres south of Fort McMurray. Meadow Creek consists of two In Situ projects: Meadow Creek East and Meadow Creek West. In early 2017, Suncor received AER approval for the Meadow Creek East Project. In early 2020, Suncor received regulatory approval of an amendment to the capacity of the project. The project is expected to be developed in two stages with anticipated gross production capacity 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 of

bitumen. The timing of the project sanction for Meadow Creek East and Meadow Creek West has been deferred and will depend on future market conditions.

In February 2018, Suncor submitted an application for the Lewis Project to the AER, which received regulatory approval in March 2021. The project is located approximately 25 kilometres northeast of Fort McMurray and is expected to be developed in stages, with anticipated peak production of 160 mbbls/d of bitumen. The timing of the 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 mining and extraction assets; however, Fort Hills uses a paraffinic froth treatment 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 paraffinic froth treated 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 2021, Suncor's share of Fort Hills production averaged 50.7 mbbls/d of bitumen (2020 – 58.1 mbbls/d) from approximately 32.6 million tonnes of bitumen ore mined (2020 – 37.7 million tonnes). Fort Hills transitioned to a one-train operation in the second quarter of 2020 in response to the COVID-19 pandemic's impact on oil prices. Production in 2021 was via one-train until Fort Hills resumed a two-train operation in December.

Due to a decline in forecast heavy crude oil prices as a result of decreased global demand due to the impacts of the COVID-19 pandemic and changes to its capital, operating and production plans, the company recorded an after-tax impairment charge of $1.376 billion on its share of Fort Hills in the first quarter of 2020.

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 located near Fort McMurray, and it includes mining operations at Mildred Lake and Aurora North. On September 30, 2021, the operatorship of Syncrude was formally transferred to Suncor concurrent with the ratification of the Joint Venture Operating Agreement, and the previous Management Services Agreement with Imperial Oil was cancelled.

In 2012, the Syncrude joint venture owners announced a plan to develop two mining areas adjacent to the current mine, the Mildred Lake West Extension (MLX-W) and the Mildred Lake East Extension (MLX-E), which are collectively expected to extend the life of Mildred Lake by a minimum of 10 years. In 2015, a decision was made by the joint venture owners to progress with the MLX-W program. The MLX-E program is expected to follow MLX-W development if economic conditions prove suitable. The MLX-W program 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 additional approvals in 2020. MLX-W was put on hold in 2020 due to the COVID-19 pandemic; however, construction activities were restarted in 2021, with first oil expected in late 2025.

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 that provide heat and electricity.

Syncrude produces a single sweet SCO product; individual joint venture owners are responsible for marketing this product. In addition, interconnecting pipelines between Syncrude's Mildred Lake site and Suncor's Oil Sands Base operations create flexibility for Syncrude to sell intermediate products to Suncor, which include bitumen and sour SCO.

Land reclamation activities at Syncrude are similar to those at Oil Sands Base; however, certain aspects of the tailings management processes at Syncrude 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 2021, Suncor's share of Syncrude production, including internal consumption and transfers through the interconnecting pipelines, averaged 172.4 mbbls/d of SCO and bitumen (2020 – 165.7 mbbls/d). Production in 2021 was impacted by maintenance activities. In the 2021 AIF, the company revised the presentation of current and prior year Syncrude production to include internally consumed diesel volumes and transfers through the interconnecting pipelines with Oil Sands Base.

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 Lease 31, through the company's 58.74% working interest in the Syncrude joint operation.

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 that 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 autonomous haulage systems at its operated mine sites. Autonomous haulage systems were deployed at the North Steepbank mine in 2018 and at Fort Hills in 2020. Full implementation at the Oil Sands Base Millennium mine is expected to be completed over the next four years. 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 2021, the company moved a total of 85.3 million gross tonnes of ore and overburden (2020 – 73.5 million gross tonnes) with autonomous haulage systems, which includes volumes from North Steepbank and Fort Hills. In 2021, Fort Hills temporarily returned to a staffed fleet to better manage congestion and interactions between staffed and autonomous operations, as Suncor ramped up mine operations to support a return to two trains.

Building upon the process used in Suncor's Tailings Reduction Operations (TRO™), Suncor has developed the permanent aquatic storage structure (PASS) fluid tailings treatment process to significantly increase the amount of fluid tailings it can treat in a more sustainable manner. PASS combines the TRO™ process with the addition of a coagulant to improve the quality of the water expressed from the treated fluid tailings. Since 2010, fluid tailings volumes at Oil Sands Base operations have remained steady, and with the implementation of PASS technology, has allowed for a greater than 5% reduction in untreated fluid tailings inventory as of the fall of 2020. Suncor is working to reduce the number of active tailings ponds overall. Even with the start of a new mining operation (Fort Hills), the total number of active

tailings ponds has been reduced since 2010, with one being surface reclaimed and three more advancing to closure.

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:

- Expanding Solvent SAGD – An enhancement of SAGD technology wherein a small volume of hydrocarbon solvent is co-injected with steam. The addition of the hydrocarbon solvent is expected to accelerate bitumen production and reduce steam requirements, process water requirements and GHG emissions. An important component of Suncor's evaluation of this technology is enhancing the understanding of solvent retention and recovery.

- Solvent+ – In solvent-based processes, a light hydrocarbon solvent such as propane or butane is used as the primary means to mobilize the bitumen. Suncor is progressing a suite of technologies referred to as Solvent+, where the + refers to a range of heating technologies that can be coupled with solvent injection. If successful, Solvent+ offers the potential for several significant environmental improvements over SAGD, including reducing upstream GHG emissions intensity by 50% to 70%.

- Non-Aqueous Extraction (NAE) – NAE is a potential new extraction process for oil sands mining operations that uses 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.

- Partial Upgrading – Partial upgrading technology is intended to develop a low-temperature thermal cracking process integrated with advanced solvent de-asphalting to examine the potential for bitumen to be partially upgraded to a transportable and marketable product. This would increase value by eliminating the need for diluent and lowering the GHG intensity compared to current upgrader processes.

- Heavy Oil Late Life Energy Recovery (HOLLER) – HOLLER technology reuses heat from mature SAGD operations to generate low-carbon power and drive down GHG emissions. It also offers the potential to sequester process or tailings water. If successful, HOLLER could lower emissions by 15% to 20% and lead to a material reduction in the size of tailings ponds.

Sales of Principal Products

Primary markets for SCO and bitumen production from Suncor's Oil Sands segment, including paraffinic froth treated 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 the company'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 2021 decreased to 116.8 mbbls/d or 48% (2020 – 130.1 mbbls/d or 65%) of total In Situ bitumen production as less In Situ bitumen feedstock was

required due to higher mined bitumen feedstock and imports of bitumen from Syncrude on the interconnecting pipelines.

	2021		2020	
Sales Volumes and Operating Revenues – Principal Products	mbbls/d	% operating revenues	mbbls/d	% operating revenues
SCO and diesel (including Syncrude)	465.7	70	467.9	80
Bitumen	183.8	27	125.6	19
Byproducts and other operating revenues (1)	n/a	3	n/a	1
	649.5		593.5	

(1) Operating revenues include revenues associated with excess electricity 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, 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., 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 the Athabasca Terminal. 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 Trans Mountain 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, and via the mainline from Rose Rock's Platteville Terminal to Suncor's Fort Lupton Station. 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 and from South Portland, Maine, on the Portland Montreal Pipeline.
- 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 Trans Mountain 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 2021, Suncor incurred royalties at an average rate of 2% of gross revenue for Oil Sands Base (2020 –0%), and at an average rate of 13% of gross revenue for Syncrude operations (2020 – 3%) due to higher prices. Oil Sands Base and the Syncrude project are both in the post-payout phase, with assessment for the year for Oil Sands Base at GRR due to a carry-forward costs balance, and for Syncrude at NRR.

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 2021, Fort Hills incurred royalties at an average rate of 2% of gross revenue (2020 – 1%) due to higher prices.

In 2021, Suncor incurred royalties for MacKay River, which is in the post-payout phase, at an average rate of 10% of gross revenue due to higher prices (2020 – 2%), and royalties at an average rate of 12% of gross revenue for Firebag (2020 – 1%), due to higher prices and reaching the post-payout phase in 2021.

Exploration and Production

E&P Canada – Assets and Operations

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 kilometres 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 (86 mbbls/d, net to Suncor) of crude oil and an oil storage capacity of 960 mbbls. Terra Nova was the first harsh environment development in North America to use an FPSO vessel. 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.

Terra Nova has been offline since the fourth quarter of 2019. In 2020, the company safely preserved the FPSO quayside and deferred the previously announced Terra Nova ALE Project until an economically viable path forward with a safe and reliable return to operations could be determined. During the third quarter of 2021, Suncor and the co-owners of the Terra Nova project finalized an agreement to restructure the project ownership and move forward with the ALE Project. The agreement increased the company's working interest to 48% from approximately 38% in exchange for a cash payment from the

exiting owners, and includes royalty and financial support from the Government of Newfoundland and Labrador.

The ALE Project is expected to extend production life by approximately 10 years, providing an additional 70 million barrels of resource for the partnership and providing many benefits to the Newfoundland and Labrador and Canadian economies in the form of taxes, royalties and employment. As part of the project, the FPSO will undergo maintenance work and a safe return to operations is anticipated before the end of 2022.

In 2021, Terra Nova production remained offline; therefore, Suncor's share of Terra Nova production averaged nil mbbls/d of crude oil (2020 – nil mbbls/d).

In the first quarter of 2020, due to a decline in forecast crude oil prices as a result of decreased global demand due to the COVID-19 pandemic as well as changes to capital, operating and production plans, the company recorded an after-tax impairment charge of $285 million on its share of the Terra Nova assets. Subsequently, in the third quarter of 2021, the company recorded a non-cash after-tax impairment reversal of $168 million on its share of the Terra Nova assets, as a result of the ALE Project moving forward and the benefit of royalty and financial support from the Government of Newfoundland and Labrador.

Hibernia and the Hibernia Southern Extension Unit

The Hibernia oilfield, encompassing the Hibernia and Ben Nevis Avalon reservoirs, is approximately 315 kilometres southeast of St. John's and was the first field to be developed in the Jeanne d'Arc Basin. Operated by Hibernia Management and Development Company Ltd., the production system is a fixed Gravity Based Structure (GBS) that sits on the ocean floor and has gross production capacity of 230 mbbls/d (46 mbbls/d, net to Suncor) of crude oil, and an 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, 2021, there were 74 wells: 41 oil production wells, 27 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 Hibernia Southern Extension Unit (HSEU). At the end of 2021, 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 2021, Suncor's share of Hibernia production averaged 19.8 mbbls/d of crude oil (2020 – 23.2 mbbls/d).

White Rose and the White Rose Extensions

White Rose is approximately 350 kilometres southeast of St. John's. Operated by Cenovus Energy Inc. (previously Husky Oil Operations Limited), White Rose uses an FPSO vessel and has gross production capacity of 140 mbbls/d (39 mbbls/d, net to Suncor) of crude oil 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, 2021, there were 44 wells: 23 oil production wells, 15 water injection wells, three gas storage wells, and three 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 includes 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 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, was sanctioned during the second quarter of 2017. The project was 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 of crude oil. Major development activity began in 2018. However, in 2020, the operator announced a full project review given the continued market uncertainty caused by the COVID-19 pandemic along with the cancellation of the 2021 construction season and has moved the project into safekeeping mode. At West White Rose, in 2021, Suncor entered into a conditional agreement to increase its interest in the White Rose assets subject to a number of conditions including an economic restart decision for the West White Rose Project by mid-2022. Should the conditions be met, Suncor has agreed to increase its ownership interest in the White Rose assets by 12.5% to approximately 40% in exchange for a cash payment by the operator to Suncor.

Due to a decline in forecast crude oil prices as a result of decreased global demand due to the COVID-19 pandemic, as well as changes to capital, operating and production plans, the company recorded an after-tax impairment charge of $137 million on its share of the White Rose assets in the first quarter of 2020. Subsequently, in the fourth quarter of 2020, the company recorded an after-tax impairment charge of $423 million on its share of the White Rose assets as a result of the significant uncertainty surrounding the future of the West White Rose Project. The book value as of December 31, 2020, was impaired to zero.

In 2021, Suncor's share of White Rose production averaged 5.4 mbbls/d of crude oil (2020 – 6.7 mbbls/d).

Hebron

The Hebron oilfield is located approximately 340 kilometres southeast of St. John's and is operated by ExxonMobil Canada Properties. 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 of crude oil, net to Suncor, ramping up over 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 2021, drilling activities continued at Hebron and are expected to continue throughout 2022. As at December 31, 2021, there were 27 wells: 18 oil production wells, four water injection wells, one gas injection well, one cuttings reinjection well and three water alternating gas injection wells. In 2021, Suncor's share of production averaged 29.2 mbbls/d of crude oil (2020 – 29.7 mbbls/d).

Other Assets

Suncor continues to pursue opportunities offshore Newfoundland and Labrador. In 2019, Suncor and Cenovus were announced as the successful bidders on exploration licence No. 1164, which is located north of White Rose. This licence carries work commitments from 2020 to 2026. In total, the company holds interests in 48 significant discovery licences and four 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 kilometres northeast of Aberdeen, Scotland. Operated by CNOOC Petroleum Europe Limited, 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 crude oil and 80 mmcf/d (24 mmcf/d, net to Suncor) of natural gas. Actual annual production levels are lower than production capacity, reflecting current reservoir capability, including natural declines, water injection limits, gas and water production limits, and asset and infrastructure reliability. Buzzard commenced production in January 2007 and consists of four bridge-linked platforms supporting wellhead facilities, production facilities, living quarters and utilities, as well as sulphur handling. As at December 31, 2021, there were 51 wells: 34 oil and gas production wells and 17 water injection wells. Buzzard Phase 2 was sanctioned in 2018 and project execution, although adversely impacted by the COVID-19 pandemic, has progressed throughout 2021 with first oil achieved in November 2021. In 2021, Suncor's share of Buzzard production averaged 18.7 mboe/d of crude oil and natural gas (2020 – 25.9 mboe/d).

Golden Eagle Area Development

On October 22, 2021, the company completed the sale of its 26.69% working interest in the Golden Eagle Area Development for gross proceeds of US$250 million net of closing adjustments and other closing costs, resulting in an after-tax gain on sale of approximately $227 million, in addition to future contingent consideration of up to US$50 million. The effective date of the sale was January 1, 2021. In 2021, Suncor's share of Golden Eagle Area Development production averaged 8.3 mboe/d of crude oil and natural gas (2020 – 7.8 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. It is located approximately 130 kilometres northwest of the Shetland Islands, in the U.K. North Sea. The project is currently in the pre-sanction phase.

Oda

The Oda field (PL405 licence) was discovered in 2011 and is located 13 kilometres 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. Drilling activities were completed in 2018, and first oil was achieved in March 2019. As at December 31, 2021, there were three wells: two production wells and one water injection well. In 2021, Suncor's share of Oda production averaged 2.7 mboe/d of crude oil and natural gas (2020 – 7.5 mboe/d).

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 kilometres 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 Norwegian Ministry of Petroleum and Energy in the first half of 2018. The field will be developed with two subsea templates, each with up to four wells, tied back to the Equinor-operated Njord platform. First oil is planned for 2023, with peak production expected to reach 29 mboe/d (5.1 mboe/d, net to Suncor) of crude oil and natural gas in 2024.

Other Assets

Suncor continues to pursue other opportunities offshore of the U.K. and Norway. The company holds interests in 15 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. Production in Libya was steady in 2021, albeit at reduced rates. The timing of a return to normal operations in Libya remains uncertain due to continued political unrest.

The estimated cost of Suncor's remaining exploration work program commitment at December 31, 2021, is US$359 million. Suncor declared force majeure for all exploration commitments in Libya effective December 14, 2014, and this declaration remains in effect.

Suncor's share of production in Libya on an economic basis averaged 3.4 mbbls/d in 2021 of crude oil (2020 – 0.8 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. and 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:

Sales Volumes	2021 mboe/d	2021 % operating revenues	2020 mboe/d	2020 % operating revenues
E&P Canada				
Crude oil	53.1	64	59.8	59
E&P International				
Crude oil and NGLs[1][2]	29.2	35	41.9	41
Natural gas	0.5	1	0.9	—
Total Exploration and Production				
Crude oil and NGLs[2]	82.3	99	101.7	100
Natural gas	0.5	1	0.9	—

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

(2) Contains immaterial amounts of NGLs.

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.

- Oda: Crude oil and natural gas is transported via the third-party operated Norpipe to the Teesside terminal in the U.K., 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 Offshore Royalty Regime 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 and the Newfoundland government finalized the Terra Nova Fiscal Agreement in 2021 , which effected changes to the existing royalty structure. Royalties consist of an initial graduated-scale basic royalty, followed by a two-tiered royalty that will become payable upon the achievement of specified levels

of profitability. The basic royalty starts at 1% of gross revenue, graduating to 10% depending on certain milestones. The Tier I royalty is equal to 20% of net revenue. The Tier II incremental royalty is on a stepped scale starting at 10% to 22.5% to reflect oil prices from US$65/bbl Brent to above US$80/bbl Brent. During 2021, Terra Nova did not pay royalties due to suspension of production (2020 – 2%).

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 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 was triggered in 2019.

Hibernia royalties (including the HSEU) and net profits interest combined to average 35% of gross revenue for 2021 (2020 – 23%), due to higher commodity prices.

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 2021, total White Rose royalties averaged 6% of gross revenue (2020 – 6%).

The Hebron royalty consists of an initial sliding-scale basic royalty, followed by a three-tiered royalty that will become payable upon the achievement of specified levels of profitability. The basic royalty starts at 1% and increases 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 2021, Hebron royalties averaged 1% of gross revenue (2020 – 1%).

E&P International

There are no royalties on oil and gas production from Offshore U.K. and Norway; however, oil and gas profits are subject to a 40% income tax rate and 78% income tax rate, respectively. 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, and 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.

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., 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 358,000 metric tonnes in 2021 (2020 – 295,000 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 2021, the plant produced 343 million litres of ethanol (2020 – 336 million litres).

Western North America

Edmonton Refinery

In the first quarter of 2021, the crude oil capacity of the Edmonton refinery increased to 146 mbbls/d (2020 – 142 mbbls/d) as a result of debottlenecking activities. The refinery 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 owners' share of production) and other producers from the Wood Buffalo and Cold Lake regions of Alberta. The refinery can process approximately 44 mbbls/d of blended heavy feedstock (comprised of 31 mbbls/d of bitumen and 13 mbbls/d of diluent) and process approximately 44 mbbls/d of sour SCO. The refinery can also process approximately 58 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 Trans Mountain 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. The Burrard distribution terminal was expanded by Suncor in 2020, which added an incremental 19 mbbls/d of export capacity, bringing the total export capacity of the terminal to 40 mbbls/d. 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, 2021 and 2020.

Average Daily Crude Throughput	Montreal		Sarnia		Edmonton(2)		Commerce City	
(mbbls/d, except as noted)	**2021**	2020	**2021**	2020	**2021**	2020	**2021**	2020
Sweet synthetic	15.0	10.5	23.4	28.6	59.0	42.9	—	—
Sour synthetic	—	—	33.7	28.6	44.0	51.8	7.5	11.0
Diluted bitumen	25.4	21.0	—	—	34.2	35.2	7.9	8.9
Sweet conventional	78.0	87.5	1.4	1.9	—	—	51.5	45.7
Sour conventional	4.7	5.5	21.2	17.4	—	—	8.6	10.5
Total	123.1	124.5	79.7	76.5	137.2	129.9	75.5	76.1
Utilization (%)	90	91	94	90	94	91	77	78
Equity crude processed(1)	13.1	10.0	51.5	53.1	102.3	94.3	7.5	11.0

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

(2) December 31, 2020 figures calculated based on 142 mbbls/d capacity, not incorporating capacity increase effective January 1, 2021.

Refined petroleum production yield mix	Montreal		Sarnia		Edmonton		Commerce City	
(%)	**2021**	2020	**2021**	2020	**2021**	2020	**2021**	2020
Gasoline	37	35	45	48	43	42	50	46
Distillates	37	37	40	37	52	52	33	34
Other	26	28	15	15	5	6	17	20

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, 2021, Suncor's ownership interests in certain pipelines were as follows:

Pipeline	Ownership	Type	Origin	Destinations
Portland-Montreal Pipeline	100.00%	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, 2021, this network consisted of 1,584 outlets across Canada, of which 786 locations are company-owned locations and 798 are branded-dealers. Selected locations along the Trans-Canada Highway contain Canada's Electric Highway™, the coast-to-coast network of fast-charging electric vehicle 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 4.2 million litres per site in 2021 (2020 – 4.1 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 110 Shell-branded sites in both Colorado and Wyoming, and with 66 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

Suncor's retail network consists of the following branded outlets supplied with Suncor fuel. These outlets are comprised of Suncor owned or leased locations, as well as third-party sites branded and supplied with branded fuel through Suncor. The number of wholesale sites is also shown in the table below.

	As at December 31	
Locations	**2021**	2020
Retail Service Stations - Canada		
Petro-Canada -branded	1,583	1,560
Sunoco -branded	1	1
	1,584	1,561
Retail Service Stations[(1)] - U.S.		
Shell -branded retail service stations - Colorado/Wyoming	145	168
Exxon -branded retail service stations - Colorado	57	48
Mobil -branded retail service stations - Colorado	18	23
	220	239
Wholesale Cardlock Sites - Canada		
Petro-Canada-branded cardlock sites (PETRO-PASS)	323	316

(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

Sales Volumes	2021 mbbls/d	2021 % operating revenues	2020 mbbls/d	2020 % operating revenues
Gasoline (includes motor and aviation gasoline)				
Eastern North America	110.2		103.6	
Western North America	115.6		110.5	
	225.8	44	214.1	43
Distillates (includes diesel and heating oils, and aviation jet fuels)				
Eastern North America	94.7		91.9	
Western North America	133.8		123.8	
	228.5	43	215.7	43
Other (includes heavy fuel oil, asphalts, petrochemicals, other)				
Eastern North America	51.3		47.5	
Western North America	22.8		26.1	
	74.1	13	73.6	14
	528.4		503.4	

Sales volumes for specific products are moderately affected by seasonal cycles: gasoline sales are typically higher during the summer driving season; heating oil sales are typically higher during the winter season; diesel sales are typically higher during the drilling season at the beginning of the year in Western Canada and during agricultural planting and harvest seasons in early spring and late summer, respectively; 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. Suncor also has the flexibility to import and export refined products to optimize domestic seasonal cycles and to capture incremental margins from market dislocations as they arise.

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.

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 NGL 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. The sanctioned Forty Mile Wind Power Project is designed to provide 200 MW of generation capacity with an estimated total capital spend of $300 million. The project is currently planned for completion in late 2022.

Suncor's wind power projects as at December 31, 2021:

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 full- and part-time employees among Suncor's business units and corporate office.

As at December 31	2021	2020
Oil Sands[1][4]	10,423	6,371
Exploration and Production[2]	296	321
Refining and Marketing[2]	2,673	2,716
Corporate[2][3][4]	3,530	3,183
Total	16,922	12,591

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

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

(3) Includes employees from the company's Projects group, which supports the business units.

(4) Suncor became operator of the Syncrude joint operation on September 30, 2021, and thus the Oil Sands segment figures include 4,241 employees and the corporate office figures include 526 employees related to the Syncrude joint operation. Refer to the Narrative Description of Suncor's Businesses – Oil Sands – Syncrude section of this AIF.

In addition to Suncor's employees, the company also uses independent contractors to supply a range of services.

Approximately 25% or 4,184 of the company's employees were covered by collective agreements at the end of 2021. The company completed negotiations in 2021 in respect of the collective agreements relating to the Sarnia refinery and the Portland-Montreal Pipeline. Negotiations for four collective agreements will take place in 2022 representing approximately 317 employees and including the Commerce City refinery and B.C. terminals.

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, equal opportunity and discrimination, respectful workplace, 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 that 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 long-term and mutually beneficial relationships. The policy makes it clear that we strive for relationships that are based on transparency, mutual respect and trust.

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 EHS&SD 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. The EHS&SD Committee reviews and makes recommendations to the Board (and to the Human Resources and Compensation Committee for the purposes of executive incentive plans) regarding the company's safety and environment related performance goals and to assess whether such goals have been met. 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 Excellence Awards program recognizes and celebrates employees and contractors who lead the way in strengthening Suncor's culture, living Suncor's purpose and values, and accelerating the Suncor transformational journey.

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 23, 2022, with an effective date of December 31, 2021. Reserves evaluations have not been updated since the effective date and, therefore, do not reflect changes in the company's reserves since that date. The preparation date of the information is January 10, 2022.

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 is based upon evaluations conducted by GLJ Ltd., contained in its report dated February 18, 2022 (the GLJ Report). GLJ is an independent qualified reserves evaluator 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 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 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 estimated reserves and associated cash flows 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, low commodity prices could have a material adverse effect on Suncor's reserves; conversely, higher commodity prices may result in higher reserves by making more projects economically viable or extending their economic life. 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, 2021. 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, such as 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 Policy section of this AIF.

Refer to the Risk Factors section of this AIF for additional information on additional 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, 2021
(forecast prices and costs) (2)

	SCO(3) (mmbbls)		Bitumen (mmbbls)		Light Crude Oil & 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	1,442	1,283	787	734	—	—	—	—	2,229	2,018
In Situ	275	228	93	73	—	—	—	—	367	301
E&P Canada	—	—	—	—	74	68	—	—	74	68
Total Canada	1,717	1,511	880	807	74	68	—	—	2,671	2,387
Offshore U.K. & Norway	—	—	—	—	39	39	2	2	40	40
Total Proved Developed Producing	1,717	1,511	880	807	114	108	2	2	2,711	2,426
Proved Developed Non-Producing										
Mining	—	—	—	—	—	—	—	—	—	—
In Situ	—	—	—	—	—	—	—	—	—	—
E&P Canada	—	—	—	—	23	20	—	—	23	20
Total Canada	—	—	—	—	23	20	—	—	23	20
Offshore U.K. & Norway	—	—	—	—	—	—	—	—	—	—
Total Proved Developed Non-Producing	—	—	—	—	23	20	—	—	23	20
Proved Undeveloped										
Mining	295	272	—	—	—	—	—	—	295	272
In Situ	715	578	478	391	—	—	—	—	1,193	969
E&P Canada	—	—	—	—	15	12	—	—	15	12
Total Canada	1,010	850	478	391	15	12	—	—	1,504	1,253
Offshore U.K. & Norway	—	—	—	—	7	7	11	11	9	9
Total Proved Undeveloped	1,010	850	478	391	23	19	11	11	1,513	1,262
Proved										
Mining	1,737	1,556	787	734	—	—	—	—	2,524	2,290
In Situ	990	805	571	464	—	—	—	—	1,561	1,269
E&P Canada	—	—	—	—	113	101	—	—	113	101
Total Canada	2,727	2,361	1,358	1,198	113	101	—	—	4,197	3,660
Offshore U.K. & Norway	—	—	—	—	46	46	13	13	49	49
Total Proved	2,727	2,361	1,358	1,198	159	147	13	13	4,246	3,708
Probable										
Mining	403	354	461	394	—	—	—	—	864	748
In Situ	1,275	977	336	254	—	—	—	—	1,611	1,231
E&P Canada	—	—	—	—	103	78	—	—	103	78
Total Canada	1,678	1,332	797	648	103	78	—	—	2,578	2,058
Offshore U.K. & Norway	—	—	—	—	16	16	6	6	17	17
Total Probable	1,678	1,332	797	648	119	94	6	6	2,595	2,075
Proved Plus Probable										
Mining	2,140	1,910	1,248	1,128	—	—	—	—	3,387	3,038
In Situ	2,265	1,783	907	718	—	—	—	—	3,172	2,501
E&P Canada	—	—	—	—	215	179	—	—	215	179
Total Canada	4,405	3,693	2,155	1,846	215	179	—	—	6,775	5,717
Offshore U.K. & Norway	—	—	—	—	63	63	19	19	66	66
Total Proved Plus Probable	4,405	3,693	2,155	1,846	278	241	19	19	6,841	5,783

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, 2021 (forecast prices and costs) (2)

	SCO[3]			Bitumen			Light Crude Oil & 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, 2020	1,980	426	2,406	865	554	1,418	—	—	—	—	—	—	2,845	980	3,824
Extensions & Improved Recovery[7]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Technical Revisions[8]	(104)	(24)	(128)	(60)	(93)	(153)	—	—	—	—	—	—	(164)	(116)	(280)
Discoveries[9]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Acquisitions[10]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions[11]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors[12]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Production[13]	(139)	—	(139)	(18)	—	(18)	—	—	—	—	—	—	(157)	—	(157)
December 31, 2021	1,737	403	2,140	787	461	1,248	—	—	—	—	—	—	2,524	864	3,387
In Situ															
December 31, 2020	997	1,286	2,283	628	328	957	—	—	—	—	—	—	1,625	1,614	3,240
Extensions & Improved Recovery[7]	3	1	4	1	(0)	1	—	—	—	—	—	—	4	0	5
Technical Revisions[8]	32	(11)	21	(24)	8	(16)	—	—	—	—	—	—	8	(3)	5
Discoveries[9]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Acquisitions[10]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions[11]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors[12]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Production[13]	(43)	—	(43)	(34)	—	(34)	—	—	—	—	—	—	(77)	—	(77)
December 31, 2021	990	1,275	2,265	571	336	907	—	—	—	—	—	—	1,561	1,611	3,172
E&P Canada															
December 31, 2020	—	—	—	—	—	—	109	100	209	—	—	—	109	100	209
Extensions & Improved Recovery[7]	—	—	—	—	—	—	—	1	1	—	—	—	—	1	1
Technical Revisions[8]	—	—	—	—	—	—	17	(3)	14	—	—	—	17	(3)	14
Discoveries[9]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Acquisitions[10]	—	—	—	—	—	—	5	2	7	—	—	—	5	2	7
Dispositions[11]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors[12]	—	—	—	—	—	—	2	3	4	—	—	—	2	3	4
Production[13]	—	—	—	—	—	—	(20)	—	(20)	—	—	—	(20)	—	(20)
December 31, 2021	—	—	—	—	—	—	113	103	215	—	—	—	113	103	215
Total Canada															
December 31, 2020	2,977	1,712	4,689	1,493	882	2,375	109	100	209	—	—	—	4,579	2,694	7,273
Extensions & Improved Recovery[7]	3	1	4	1	(0)	1	—	1	1	—	—	—	4	1	5
Technical Revisions[8]	(72)	(35)	(107)	(84)	(84)	(169)	17	(3)	14	—	—	—	(139)	(122)	(261)
Discoveries[9]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Acquisitions[10]	—	—	—	—	—	—	5	2	7	—	—	—	5	2	7
Dispositions[11]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors[12]	—	—	—	—	—	—	2	3	4	—	—	—	2	3	4
Production[13]	(182)	—	(182)	(52)	—	(52)	(20)	—	(20)	—	—	—	(253)	—	(253)
December 31, 2021	2,727	1,678	4,405	1,358	797	2,155	113	103	215	—	—	—	4,197	2,578	6,775

Please see Notes (1) through (13) at the end of the reserves data section for important information about volumes in this table. Suncor's resources in Libya and Syria are classified as contingent resources, and are not disclosed above.

Reconciliation of Gross Reserves[1] *(continued)*
as at December 31, 2021
(forecast prices and costs) [2]

	SCO[3]			Bitumen			Light Crude Oil & 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, 2020	—	—	—	—	—	—	61	22	83	12	5	17	63	23	86
Extensions & Improved Recovery[7]	—	—	—	—	—	—	1	0	1	0	0	0	1	0	1
Technical Revisions[8]	—	—	—	—	—	—	(1)	(3)	(3)	2	1	2	(1)	(2)	(3)
Discoveries[9]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Acquisitions[10]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions[11]	—	—	—	—	—	—	(6)	(3)	(9)	(0)	(0)	(0)	(6)	(3)	(9)
Economic Factors[12]	—	—	—	—	—	—	2	(1)	1	0	(0)	0	2	(1)	1
Production[13]	—	—	—	—	—	—	(11)	—	(11)	(1)	—	(1)	(11)	—	(11)
December 31, 2021	—	—	—	—	—	—	46	16	63	13	6	19	49	17	66
Total															
December 31, 2020	2,977	1,712	4,689	1,493	882	2,375	170	123	292	12	5	17	4,642	2,717	7,359
Extensions & Improved Recovery[7]	3	1	4	1	(0)	1	1	1	1	0	0	0	5	1	6
Technical Revisions[8]	(72)	(35)	(107)	(84)	(84)	(169)	16	(5)	11	2	1	2	(140)	(124)	(264)
Discoveries[9]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Acquisitions[10]	—	—	—	—	—	—	5	2	7	—	—	—	5	2	7
Dispositions[11]	—	—	—	—	—	—	(6)	(3)	(9)	(0)	(0)	(0)	(6)	(3)	(9)
Economic Factors[12]	—	—	—	—	—	—	4	1	5	0	(0)	0	4	1	5
Production[13]	(182)	—	(182)	(52)	—	(52)	(30)	—	(30)	(1)	—	(1)	(264)	—	(264)
December 31, 2021	2,727	1,678	4,405	1,358	797	2,155	159	119	278	13	6	19	4,246	2,595	6,841

Please see Notes (1) through (13) at the end of the reserves data section for important information about volumes in this table. Suncor's resources in Libya and Syria are classified as contingent resources, and are not disclosed above.

Notes to Reserves Data Tables
as at December 31, 2021

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

(2) See the Notes to the 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 oil and medium crude oil for E&P Canada include immaterial quantities of heavy crude oil as follows: proved developed producing of 53 mmbbls, proved undeveloped of 2 mmbbls, proved of 55 mmbbls, probable of 25 mmbbls and proved plus probable of 80 mmbbls. Net volumes of light crude oil & medium crude oil for E&P Canada include immaterial quantities of heavy crude oil as follows: proved developed producing of 51 mmbbls, proved undeveloped of 1 mmbbls, proved of 52 mmbbls, probable of 18 mmbbls and proved plus probable of 70 mmbbls.

(5) Light crude oil and medium crude oil technical revisions for E&P Canada include quantities of heavy crude oil as follows: proved of 12 mmbbls, probable of (0.1) mmbbls and proved plus probable of 12 mmbbls.

(6) Conventional natural gas includes immaterial amounts of NGLs (0.6 mmbbls of proved and 0.8 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 2021 are primarily a result of drilling extensions and improved recovery at Firebag.

(8) Technical revisions include changes in previous estimates resulting from new technical data or revised interpretations. Changes in 2021 are primarily due to new information obtained during the year, including drilling results and ongoing field performance. In 2021, Mining changes are primarily due to mine plan updates at Fort Hills and Syncrude, the majority of which improve the economics. In 2021, In Situ and E&P changes are primarily due to production performance updates.

(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 2021.

(10) Acquisitions are additions to reserves estimates as a result of purchasing interests in oil and gas properties. In 2021, Suncor increased its working interest in Terra Nova through acquisition and in Hibernia through redetermination.

(11) Dispositions are reductions in reserves estimates as a result of selling all or a portion of an interest in oil and gas properties. In 2021, Suncor divested its interest in the Golden Eagle Area Development – refer to discussion in E&P International – Assets and Operations section above.

(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.

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, 2021
(forecast prices and costs)

	(in $ millions, discounted at % per year)					Unit Value(2)
	0%	5%	10%	15%	20%	($/boe)
Proved Developed Producing						
Mining	27,046	25,954	20,318	16,126	13,232	10.07
In Situ	11,546	10,037	8,828	7,873	7,112	29.34
E&P Canada	3,503	3,184	2,884	2,629	2,417	42.29
Total Canada	42,096	39,175	32,030	26,628	22,761	13.42
Offshore U.K. & Norway	1,705	1,686	1,574	1,449	1,334	39.71
Total Proved Developed Producing	43,801	40,861	33,604	28,077	24,095	13.85
Proved Developed Non-Producing						
Mining	—	—	—	—	—	
In Situ	—	—	—	—	—	
E&P Canada	247	316	341	344	335	16.88
Total Canada	247	316	341	344	335	16.88
Offshore U.K. & Norway	—	—	—	—	—	
Total Proved Developed Non-Producing	247	316	341	344	335	16.88
Proved Undeveloped						
Mining	3,715	2,473	1,419	786	416	5.22
In Situ	35,277	18,676	10,803	6,733	4,454	11.15
E&P Canada	491	438	382	332	290	31.47
Total Canada	39,483	21,587	12,605	7,852	5,161	10.06
Offshore U.K. & Norway	568	436	350	290	246	38.79
Total Proved Undeveloped	40,051	22,023	12,955	8,142	5,407	10.27
Proved						
Mining	30,761	28,428	21,737	16,913	13,649	9.49
In Situ	46,823	28,713	19,631	14,606	11,566	15.47
E&P Canada	4,241	3,937	3,608	3,306	3,042	35.87
Total Canada	81,826	61,078	44,976	34,825	28,257	12.29
Offshore U.K. & Norway	2,273	2,122	1,924	1,739	1,580	39.54
Total Proved	84,099	63,200	46,900	36,564	29,837	12.65
Probable						
Mining	19,855	9,650	5,417	3,507	2,536	7.24
In Situ	76,271	20,169	7,528	3,850	2,473	6.11
E&P Canada	5,103	3,650	2,676	2,030	1,590	34.23
Total Canada	101,228	33,469	15,620	9,386	6,599	7.59
Offshore U.K. & Norway	1,066	852	692	578	497	40.72
Total Probable	102,294	34,321	16,312	9,965	7,096	7.86
Proved Plus Probable						
Mining	50,616	38,078	27,154	20,419	16,185	8.94
In Situ	123,094	48,881	27,159	18,456	14,039	10.86
E&P Canada	9,344	7,587	6,284	5,335	4,633	35.16
Total Canada	183,054	94,547	60,597	44,211	34,857	10.60
Offshore U.K. & Norway	3,340	2,974	2,616	2,317	2,077	39.84
Total Proved Plus Probable	186,394	97,521	63,212	46,528	36,934	10.93

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, 2021
(forecast prices and costs)

	(in $ millions, discounted at % per year)				
	0%	5%	10%	15%	20%
Proved Developed Producing					
Mining	19,905	20,730	16,319	12,941	10,609
In Situ	9,066	7,888	6,932	6,175	5,573
E&P Canada	2,892	2,649	2,406	2,196	2,019
Total Canada	31,863	31,267	25,657	21,312	18,200
Offshore U.K. & Norway	1,227	1,179	1,085	989	905
Total Proved Developed Producing	33,091	32,446	26,742	22,302	19,105
Proved Developed Non-Producing					
Mining	—	—	—	—	—
In Situ	—	—	—	—	—
E&P Canada	166	220	241	244	237
Total Canada	166	220	241	244	237
Offshore U.K. & Norway	—	—	—	—	—
Total Proved Developed Non-Producing	166	220	241	244	237
Proved Undeveloped					
Mining	2,534	1,764	976	501	227
In Situ	26,979	14,072	8,026	4,935	3,220
E&P Canada	365	324	280	240	208
Total Canada	29,878	16,159	9,282	5,676	3,655
Offshore U.K. & Norway	124	120	117	112	108
Total Proved Undeveloped	30,002	16,279	9,399	5,789	3,762
Proved					
Mining	22,440	22,494	17,295	13,442	10,836
In Situ	36,045	21,959	14,958	11,110	8,793
E&P Canada	3,423	3,192	2,927	2,680	2,463
Total Canada	61,907	47,646	35,180	27,232	22,092
Offshore U.K. & Norway	1,351	1,299	1,202	1,102	1,012
Total Proved	63,258	48,945	36,381	28,334	23,104
Probable					
Mining	15,476	7,399	4,063	2,589	1,856
In Situ	58,680	15,381	5,755	2,970	1,925
E&P Canada	3,826	2,747	2,009	1,518	1,185
Total Canada	77,982	25,528	11,826	7,077	4,965
Offshore U.K. & Norway	523	439	367	313	274
Total Probable	78,505	25,967	12,193	7,391	5,240
Proved Plus Probable					
Mining	37,916	29,893	21,358	16,032	12,692
In Situ	94,724	37,340	20,712	14,080	10,717
E&P Canada	7,249	5,939	4,935	4,197	3,648
Total Canada	139,889	73,173	47,006	34,309	27,058
Offshore U.K. & Norway	1,874	1,739	1,569	1,415	1,287
Total Proved Plus Probable	141,763	74,912	48,575	35,724	28,344

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

Total Future Net Revenues(1)
as at December 31, 2021
(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	183,935	17,851	92,963	25,782	20,292	27,046	7,141	19,905
In Situ	31,697	5,029	11,554	2,844	722	11,546	2,480	9,066
E&P Canada	6,819	665	1,486	127	1,038	3,503	611	2,892
Total Canada	222,450	23,545	106,004	28,753	22,052	42,096	10,233	31,863
Offshore U.K. & Norway	3,771	—	1,378	128	560	1,705	478	1,227
Total Proved Developed Producing	226,220	23,545	107,382	28,881	22,611	43,801	10,710	33,091
Proved Developed Non-Producing								
Mining	—	—	—	—	—	—	—	—
In Situ	—	—	—	—	—	—	—	—
E&P Canada	2,140	220	931	192	550	247	81	166
Total Canada	2,140	220	931	192	550	247	81	166
Offshore U.K. & Norway	—	—	—	—	—	—	—	—
Total Proved Developed Non-Producing	2,140	220	931	192	550	247	81	166
Proved Undeveloped								
Mining	28,590	2,270	16,972	4,091	1,542	3,715	1,181	2,534
In Situ	106,353	19,178	32,147	18,499	1,252	35,277	8,298	26,979
E&P Canada	1,381	342	213	305	29	491	126	365
Total Canada	136,324	21,791	49,332	22,895	2,823	39,483	9,605	29,878
Offshore U.K. & Norway	828	—	154	57	48	568	445	124
Total Proved Undeveloped	137,152	21,791	49,486	22,952	2,871	40,051	10,049	30,002
Proved								
Mining	212,525	20,121	109,935	29,874	21,833	30,761	8,322	22,440
In Situ	138,049	24,208	43,701	21,343	1,975	46,823	10,778	36,045
E&P Canada	10,339	1,228	2,630	623	1,617	4,241	818	3,423
Total Canada	360,914	45,556	156,267	51,840	25,425	81,826	19,918	61,907
Offshore U.K. & Norway	4,599	—	1,532	186	608	2,273	923	1,351
Total Proved	365,512	45,556	157,799	52,026	26,033	84,099	20,841	63,258
Probable								
Mining	84,395	11,350	38,139	10,262	4,790	19,855	4,378	15,476
In Situ	216,678	47,015	59,768	32,042	1,582	76,271	17,591	58,680
E&P Canada	9,996	2,652	1,512	502	227	5,103	1,277	3,826
Total Canada	311,069	61,017	99,419	42,807	6,598	101,228	23,246	77,982
Offshore U.K. & Norway	1,716	—	591	22	38	1,066	544	523
Total Probable	312,785	61,017	100,009	42,828	6,636	102,294	23,790	78,505
Proved Plus Probable								
Mining	296,920	31,471	148,074	40,136	26,623	50,616	12,700	37,916
In Situ	354,727	71,223	103,469	53,385	3,556	123,094	28,370	94,724
E&P Canada	20,335	3,879	4,142	1,126	1,844	9,344	2,095	7,249
Total Canada	671,982	106,573	255,685	94,647	32,023	183,054	43,165	139,889
Offshore U.K. & Norway	6,315	—	2,123	207	645	3,340	1,466	1,874
Total Proved Plus Probable	678,297	106,573	257,808	94,854	32,669	186,394	44,631	141,763

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

Future Net Revenues by Product Type(1)
as at December 31, 2021
(forecast prices and costs)

(before income taxes, discounted at 10% per year)	$ millions	Unit Value $/boe(2)
Proved Developed Producing		
SCO	21,582	14.28
Bitumen	7,563	9.37
Light Crude Oil & Medium Crude Oil	2,389	42.26
Heavy Crude Oil	2,056	40.32
Conventional Natural Gas(3)	14	42.92
Total Proved Developed Producing	33,604	13.85
Proved		
SCO	30,337	12.85
Bitumen	11,031	9.21
Light Crude Oil & Medium Crude Oil	3,437	36.20
Heavy Crude Oil	1,930	37.02
Conventional Natural Gas(3)	166	76.21
Total Proved	46,900	12.65
Proved Plus Probable		
SCO	41,094	11.13
Bitumen	13,218	7.16
Light Crude Oil & Medium Crude Oil	6,035	35.24
Heavy Crude Oil	2,613	37.34
Conventional Natural Gas(3)	251	80.25
Total Proved Plus Probable	63,212	10.93

(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 some 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. The upgrader operating and sustaining capital costs are pro-rated to the estimated upgrader capacity available for In Situ volumes and considered in the estimation. For total proved plus probable reserves, approximately 61% of Firebag bitumen production is expected to be upgraded to SCO by 2037 and 100% thereafter. These assumptions have resulted in a $0.7 billion increase in the net present value of future net revenues (total proved plus probable reserves, before tax, discounted at 10%) attributable to In Situ production relative to the bitumen sale-only scenario.

Power sale revenues and the natural gas fuel expense associated with excess electricity 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 Report, were derived using averages of forecasts developed by GLJ (dated January 1, 2022), Sproule Associates Limited (dated December 31, 2021) and McDaniel & Associates Consultants Ltd. (dated January 1, 2022), all of whom are independent qualified reserves evaluators. 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 2022, 2.3% in 2023 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
2021[8]	70.75	67.95	54.90	80.30	79.06	3.52	16.82
2022	75.33	72.83	74.43	86.82	91.85	3.56	25.84
2023	71.46	68.78	69.17	80.73	85.53	3.20	15.13
2024	69.62	66.76	66.54	78.01	82.98	3.05	10.50
2025	71.01	68.09	67.87	79.57	84.63	3.10	10.71
2026	72.44	69.45	69.23	81.16	86.33	3.17	10.92
2027	73.88	70.84	70.61	82.78	88.05	3.23	11.15
2028	75.36	72.26	72.02	84.44	89.82	3.30	11.37
2029	76.87	73.70	73.46	86.13	91.61	3.36	11.59
2030	78.40	75.18	74.69	87.85	93.44	3.43	11.82
2031	79.97	76.68	76.19	89.60	95.32	3.50	12.06
2032	81.57	78.21	77.71	91.40	97.22	3.57	12.06
2033	83.21	79.78	79.26	93.23	99.17	3.64	12.30
2034	84.87	81.38	80.85	95.09	101.15	3.71	12.54
2035	86.57	83.00	82.47	96.99	103.17	3.79	12.80
2036	88.30	84.66	84.11	98.93	105.24	3.86	13.05
2037+	+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 2021 reflect the company's historical weighted average prices.

Forecast Foreign Exchange Rates Impacting Forecast Prices

Forecast Year	US$/Cdn$ Exchange Rate	Cdn$/€ Exchange Rate	Cdn$/£ Exchange Rate
2022	0.797	1.431	1.694
2023	0.797	1.456	1.694
2024	0.797	1.494	1.701
2025	0.797	1.494	1.701
2026	0.797	1.494	1.701
2027+	0.797	1.494	1.701

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 2021 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, 2021
(forecast prices and costs)

($ millions)	2022	2023	2024	2025	2026	Remainder	Total	Discounted at 10%
Proved								
Mining	2,585	2,810	2,628	2,266	2,328	17,256	29,874	17,377
In Situ	1,040	661	579	375	692	17,997	21,343	8,069
E&P Canada	299	47	60	102	25	91	623	507
Total Canada	3,923	3,518	3,267	2,743	3,045	35,344	51,840	25,953
Offshore U.K. & Norway	91	4	8	4	4	74	186	130
Total Proved	4,014	3,522	3,275	2,747	3,049	35,418	52,026	26,083
Proved Plus Probable								
Mining	2,745	2,982	2,796	2,404	2,478	26,731	40,136	20,148
In Situ	829	612	698	481	490	50,276	53,385	9,000
E&P Canada	299	96	144	184	134	270	1,126	820
Total Canada	3,873	3,690	3,637	3,069	3,101	77,277	94,647	29,968
Offshore U.K. & Norway	91	4	8	4	4	96	207	134
Total Proved Plus Probable	3,964	3,694	3,646	3,073	3,106	77,372	94,854	30,102

(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 2022 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 autonomous haulage systems.
- For both Firebag and MacKay River operations within In Situ, the drilling of new well pairs, the design and construction of new well pads, and facility maintenance that are expected to maintain existing production levels in future years.
- For E&P Canada, capital investments related to ALE at Terra Nova, which are expected to be partially reimbursed by government, and development drilling at Hebron and Hibernia.
- For E&P International, development drilling at Buzzard, Fenja and Oda.

Future development costs disclosed above are associated with reserves as evaluated by GLJ and are subject to change based on many factors, including economic conditions. Management currently believes that internally generated cash flows, existing and future credit facilities, issuing commercial paper and, if needed, 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 Report. 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, 2021, Suncor estimated its undiscounted, uninflated abandonment and reclamation costs for its upstream assets to be approximately $13.6 billion (discounted at 10%, approximately $3.0 billion) excluding Refining and Marketing liabilities ($0.2 billion, undiscounted and uninflated). Abandonment and reclamation costs are limited to current disturbances at December 31, 2021, 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, 2021. Suncor estimates that it will incur $1.1 billion of its identified abandonment and reclamation costs during the next three years (undiscounted: 2022 – $0.3 billion, 2023 – $0.4 billion, 2024 – $0.4 billion), more than 67% 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 for Suncor's Oil Sands operations 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 processing facilities and well pads, existing and future reserve wells and associated service wells, disturbed lease sites, and future lease site disturbances. Abandonment and reclamation cost estimates included in the net present values of the company's proved and probable reserves for Suncor's E&P operations are on a life of field basis, accounting for abandonment and reclamation of existing and estimated future development items. Key abandonment liabilities are associated with offshore equipment and well abandonments. Offshore equipment includes topsides or processing facilities; platforms, FPSOs or GBSs; gathering systems and other subsea equipment such as templates. Approximately $32.7 billion (inflated and undiscounted) has been deducted as abandonment and reclamation costs in estimating the future net revenues from proved plus probable reserves, including $30.2 billion related to the company's oil sands upgraders, extraction facilities, tailings ponds, subsurface wells and central processing facilities.

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)

	2019		2020		2021	
	First Attributed	Total as at December 31, 2019	First Attributed	Total as at December 31, 2020	**First Attributed**	**Total as at December 31, 2021**
SCO (mmbbls)						
Mining	—	—	297	297	**—**	**295**
In Situ	53	627	—	746	**2**	**715**
Total SCO	53	627	297	1,042	**2**	**1,010**
Bitumen (mmbbls)						
Mining	—	—	—	—	**—**	**—**
In Situ	52	679	—	523	**1**	**478**
Total Bitumen	52	679	—	523	**1**	**478**
Light Crude Oil & Medium Crude Oil (mmbbls)						
E&P Canada	2	16	4	18	**—**	**13**
Offshore U.K. & Norway	1	8	1	8	**1**	**7**
Total Light Crude Oil & Medium Crude Oil	3	24	6	25	**1**	**20**
Heavy Crude Oil (mmbbls)						
E&P Canada	—	28	—	15	**—**	**2**
Offshore U.K. & Norway	—	—	—	—	**—**	**—**
Total Heavy Crude Oil	—	28	—	15	**—**	**2**
Conventional Natural Gas (bcfe)						
E&P Canada	—	—	—	—	**—**	**—**
Offshore U.K. & Norway (2)	0	13	—	11	**0**	**11**
Total Conventional Natural Gas	0	13	—	11	**0**	**11**
Total (mmboe)	108	1,359	302	1,608	**3**	**1,513**

(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)

	2019		2020		2021	
	First Attributed	Total as at December 31, 2019	First Attributed	Total as at December 31, 2020	**First Attributed**	**Total as at December 31, 2021**
SCO (mmbbls)						
Mining	—	321	—	23	**—**	**23**
In Situ	—	1,070	116	1,195	**0**	**1,185**
Total SCO	—	1,391	116	1,218	**0**	**1,208**
Bitumen (mmbbls)						
Mining	—	—	—	—	**—**	**—**
In Situ	—	267	24	289	**—**	**283**
Total Bitumen	—	267	24	289	**—**	**283**
Light Crude Oil & Medium Crude Oil (mmbbls)						
E&P Canada	6	96	23	55	**8**	**60**
Offshore U.K. & Norway	1	8	0	3	**0**	**3**
Total Light Crude Oil & Medium Crude Oil	7	104	24	58	**8**	**63**
Heavy Crude Oil (mmbbls)						
E&P Canada	—	15	—	8	**—**	**2**
Offshore U.K. & Norway	—	—	—	—	**—**	**—**
Total Heavy Crude Oil	—	15	—	8	**—**	**2**
Conventional Natural Gas (bcfe)						
E&P Canada	—	—	—	—	**—**	**—**
Offshore U.K. & Norway (2)	0	15	0	3	**0**	**4**
Total Conventional Natural Gas	0	15	0	3	**0**	**4**
Total (mmboe)	7	1,780	163	1,573	**8**	**1,556**

(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 79% of Suncor's gross proved undeveloped reserves and 94% of Suncor's gross probable undeveloped reserves have been assigned to reserves areas that 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 new pads and, upon approval, commences development of the reserves and wells surrounding the declining areas. This entails drilling well pairs and constructing sustaining pads and may take up to 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 19% of Suncor's gross proved undeveloped reserves, and 1% of Suncor's gross probable undeveloped reserves and relate to the Syncrude MLX-W mining area, which is well-delineated by core hole drilling. Further drilling is planned in 2022 for the opening cut area and infill cores along the west pit limit. The Syncrude MLX-W mining area received AER approval in 2019 and remaining approvals were obtained in the first quarter of 2020. Development of the MLX-W mining area was put on hold in 2020; however, construction activities were restarted in 2021. Development of MLX-W consists of typical mine development activities in addition to a bridge over the MacKay River, and will utilize existing ore processing and extraction facilities at Syncrude's Mildred Lake operation. The MLX-W program is expected to sustain bitumen production levels at Mildred Lake after resource depletion at the North Mine. MLX-W reserves will remain as undeveloped until its major components, such as the bridge, are completed.

E&P

Undeveloped conventional reserves (light crude oil and medium crude oil, heavy crude oil and natural gas) constitute approximately 2% of Suncor's gross proved undeveloped reserves and approximately 4% of Suncor's gross probable undeveloped reserves and relate to the company's offshore E&P assets, mainly associated with future drilling at Hebron, and under-drilled or undrilled fault blocks related to areas in Hibernia, infill drilling in Oda, and development drilling and startup of the Fenja Project in 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, 2021. 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	4,358,376	3,216,885
Libya	3,117,800	1,422,900
Syria	345,194	345,194
Norway	185,185	54,949
U.K.	189,334	156,580
Total	8,195,889	5,196,508

Suncor's properties with no attributed reserves 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 2022, Suncor's rights to 85,163 net hectares in Canada, 11,770 net hectares in Norway and nil net hectares in the U.K. are scheduled to expire. The lands expiring in 2022 include approximately 33,024 net hectares in In Situ and 26,922 net hectares in Mining. Substantial portions of expiring lands may have their tenure continued beyond 2022 through the conduct of work programs and/or the payment of prescribed fees to the mineral rights owner.

Work Commitments

Suncor's properties in Libya have no attributed reserves. The practice of governments requiring companies to pledge to carry out work commitments in exchange for the right to carry out exploration and development activities is common in certain parts of the world, including Libya. Suncor has work commitments primarily for conducting seismic programs and drilling exploration wells. As at December 31, 2021, Suncor estimates that the value of the work commitment associated with its properties with no attributed reserves was US$359 million. Due to the political unrest in Libya, it is uncertain when the work commitments will be incurred.

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, 2021.

	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]	448.0	448.0	17.0	17.0	—	—	—	—
Newfoundland and Labrador	74.0	16.1	26.0	10.7	—	—	—	—
Offshore U.K. & Norway	33.0	9.9	3.0	0.9	—	—	—	—
Other International[5]	—	—	422.0	212.6	—	—	6.0	6.0
Total	555.0	474.0	468.0	241.2	—	—	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 exploration and development activities for the year ended December 31, 2021.

($ millions)	Exploration costs	Proved property acquisition costs	Unproved property acquisition costs	Development costs	Total
Canada – Mining and In Situ	15	—	—	3,172	3,187
Canada – E&P Canada	1	—	—	120	121
Total Canada	**16**	**—**	**—**	**3,292**	**3,308**
Offshore U.K. & Norway	29	—	—	158	187
Other International	6	—	—	—	6
Total	**51**	**—**	**—**	**3,450**	**3,501**

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, 2021.

	Exploratory wells[1]		Development wells	
Total number of wells completed	Gross	Net	Gross	Net
Canada – Oil Sands				
Oil	—	—	43.0	43.0
Service[2]	—	—	40.0	40.0
Stratigraphic test[3]	2.0	2.0	330.0	224.4
Total	2.0	2.0	413.0	307.4
Canada – E&P Canada				
Oil	—	—	3.0	0.6
Dry hole	—	—	—	—
Natural gas	—	—	—	—
Service[2]	—	—	2.0	0.4
Stratigraphic test	—	—	—	—
Total	—	—	5.0	1.0
Total Canada				
Oil	—	—	46.0	43.6
Dry hole	—	—	—	—
Natural gas	—	—	—	—
Service[2]	—	—	42.0	40.4
Stratigraphic test	2.0	2.0	330.0	224.4
Total	2.0	2.0	418.0	308.4
Offshore U.K. & Norway				
Oil	—	—	—	—
Dry hole	—	—	—	—
Service[2]	—	—	1.0	0.2
Stratigraphic test	—	—	—	—
Total	—	—	1.0	0.2

(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 2021 included:

- For Mining, at Oil Sands Base, development activities included asset sustainment activities related to the company's planned maintenance program, the continued development of tailings infrastructure and construction of a new cogeneration facility. At Fort Hills, development activities focused on construction of tailings infrastructure and mine advancement activities. At Syncrude, development activities included asset sustainment expenditures, scheduled turnaround and planned maintenance activities.
- For In Situ, the drilling of new well pairs, infill and sidetracked wells at Firebag and MacKay River that are expected to assist in maintaining production levels in future years. Also included are stratigraphic test well and observation well drilling programs.
- For E&P Canada, spending on the Terra Nova ALE Project, which was partially reimbursed by government, and drilling activities at Hebron.
- For E&P International, work on the Norwegian Fenja Project.

For significant exploration and development activities expected to occur in 2022 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]

2021	Q1	Q2	Q3	Q4	Year Ended
Canada - Oil Sands					
Upgraded product (SCO and diesel) production (mbbls/d)					
Oil Sands operations	329.6	326.8	221.0	332.7	301.6
Syncrude	190.3	110.4	184.5	182.3	167.0
Total upgraded production	519.9	437.2	405.5	515.0	468.6
Non-upgraded bitumen production (mbbls/d)					
Oil Sands operations	119.5	133.2	148.8	95.4	124.9
Fort Hills	51.2	45.3	50.8	55.5	50.7
Total Oil Sands non-upgraded bitumen production	170.7	178.5	199.6	150.9	175.6
Total production (mbbls/d)	**690.6**	**615.7**	**605.1**	**665.9**	**644.2**
Netbacks[3][4]					
Bitumen ($/bbl)					
Average price realized[2]	42.53	50.20	59.91	62.05	53.80
Royalties	(0.83)	(3.65)	(7.99)	(9.50)	(5.53)
Production costs	(13.88)	(15.55)	(18.10)	(20.92)	(17.13)
Netback	27.82	31.00	33.82	31.63	31.14
SCO and diesel ($/bbl)					
Average price realized[2]	65.22	76.50	80.21	89.38	77.73
Royalties	(3.10)	(4.01)	(9.33)	(10.64)	(6.75)
Production costs	(26.64)	(32.04)	(33.44)	(29.34)	(30.16)
Netback	35.48	40.45	37.44	49.40	40.82
Average Oil Sands Segment ($/bbl)					
Average price realized[2]	59.32	68.68	73.78	82.20	70.96
Royalties	(2.50)	(3.90)	(8.91)	(10.36)	(6.41)
Production costs	(23.34)	(27.14)	(28.58)	(27.13)	(26.48)
Netback	33.48	37.64	36.29	44.71	38.07
Exploration and Production - Light Crude Oil & Medium Crude Oil					
Exploration and Production Canada (mbbls/d)	58.0	57.5	54.4	47.6	54.4
Exploration and Production Offshore U.K. & Norway (mboe/d)	37.3	26.5	39.1	29.8	33.1
Total production volumes (mboe/d)	**95.3**	**84.0**	**93.5**	**77.4**	**87.5**
Netbacks[3][4]					
Canada - Light Crude Oil & Medium Crude Oil ($/bbl)					
Average price realized[2]	73.91	80.65	90.23	98.42	84.70
Royalties	(9.24)	(13.26)	(11.88)	(14.59)	(12.20)
Production costs	(11.27)	(10.27)	(12.87)	(13.42)	(11.74)
Netback	53.40	57.12	65.48	70.41	60.76
Offshore U.K. & Norway - Light Crude Oil & Medium Crude Oil ($/boe)[5]					
Average price realized[2]	69.51	78.82	85.29	100.14	82.16
Production costs	(8.05)	(13.20)	(10.30)	(10.19)	(10.40)
Netback[4]	61.46	65.62	74.99	89.95	71.76

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

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

(3) Netbacks are based on sales volumes.

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

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

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, 2021.

	SCO	Bitumen	Light Crude Oil & Medium Crude Oil
	mbbls/d	mbbls/d	mboe/d
Mining – Suncor	211.6	—	—
Mining – Syncrude	167.0		—
Mining – Fort Hills	—	50.7	—
Firebag	90.0	89.0	—
MacKay River	—	35.9	—
Buzzard	—	—	18.7
GEAD	—	—	8.3
Oda	—	—	2.7
Hibernia	—	—	19.8
White Rose	—	—	5.4
Terra Nova	—	—	—
Hebron[2]	—	—	29.2

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

(2) The majority of volumes shown for Hebron are heavy crude oil volumes.

Production Estimates

The table below outlines the production estimates for 2022 that are included in the estimates of proved reserves and probable reserves as at December 31, 2021.

	SCO (mbbls/d)[1]		Bitumen (mbbls/d)[1]		Light Crude Oil & 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	460	410	186	161	53	48	—	—	699	619
Probable	32	26	5	3	5	5	—	—	42	34
Proved Plus Probable	492	436	191	164	58	53	—	—	741	653
Offshore U.K. & Norway										
Proved	—	—	—	—	21	21	3	3	21	21
Probable	—	—	—	—	4	4	2	2	4	4
Proved Plus Probable	—	—	—	—	25	25	5	5	25	25
Total[1][2]										
Proved	460	410	186	161	73	69	3	3	721	640
Probable	32	26	5	3	9	8	2	2	46	38
Proved Plus Probable	492	436	191	164	82	77	5	5	767	678

(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 2022.

Proved

- From Millennium and North Steepbank: 191 mbbls/d of SCO, which represents approximately 27% of total estimated production for 2022.
- From Firebag: 170 mbbls/d of SCO and bitumen (111 mbbls/d and 60 mbbls/d, respectively), which represents approximately 24% of total estimated production for 2022.
- From Syncrude: 159 mbbls/d of SCO, which represents approximately 22% of total estimated production for 2022.

Proved Plus Probable

- From Millennium and North Steepbank: 204 mbbls/d of SCO, which represents approximately 27% of total estimated production for 2022.
- From Firebag: 174 mbbls/d of SCO and bitumen (115 mbbls/d and 59 mbbls/d, respectively), which represents approximately 23% of total estimated production for 2022.
- From Syncrude: 173 mbbls/d of SCO from Syncrude, which represents approximately 23% of total estimated production for 2022.

None of the company's light and 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 2022.

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 2021 audited Consolidated Financial Statements and related MD&A for the year ended December 31, 2021.

Tax Horizon

In 2021, 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. and U.K. production. Based on projected future net earnings, Suncor is expected to be cash taxable on the majority of its earnings in 2022.

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 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). 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.

On July 1, 2020, the Canada-United States-Mexico Agreement (CUSMA) came into force. CUSMA has been ratified by all three member states. CUSMA does not contain an energy-specific chapter. Instead, provisions governing the export of oil are found throughout the agreement. CUSMA allows for the free flow of oil exports between Canada, Mexico and the United States and requires the parties to treat imported goods no less favourably than domestic goods. Canada is free to determine whether exports of energy resources to the United States or Mexico will be allowed, subject to certain conditions. Canada maintains tariff-free access to the U.S. and Mexican markets.

CUSMA restricts the parties from adopting or maintaining export and import price requirements, except under the countervailing and anti-dumping duty measures set out in CUSMA, and from requiring, as a condition for importation, that the persons of another party establish a contractual or other relationship with distributors in its territory.

CUSMA contains a "non-market economy" clause that requires parties to notify the other parties three months before entering into free trade talks with a non-market economy. A "non-market economy" may include China or other potential importers of Canadian oil and gas exports. The "non-market economy" clause states that if one party enters into a free trade agreement with a non-market country, the other parties may terminate CUSMA on six months' notice. To date, none of the parties to CUSMA have entered into a free trade agreement with a non-market economy.

Canada and the United States have also entered into an energy-specific side letter which, among other things, mandates the countries to ensure that measures governing access to or use of energy infrastructure, including pipeline networks, are neither unduly discriminatory nor unduly preferential. The energy side letter also encourages Canada and the United States to ensure that the implementation of energy regulatory measures is orderly and equitable, and avoids disruption of contractual relationships to the maximum extent practicable.

On January 25, 2021, U.S. President Joe Biden signed the "Executive Order on Ensuring the Future is Made in All of America by All of America's Workers." The order states that "the United States Government should, consistent with applicable law, use terms and conditions of Federal financial assistance awards and Federal procurements to maximize the use of goods, products, and materials produced in, and

services offered in, the United States." Waivers from the order are provided for in certain circumstances. The order applies to all U.S. government procurement and supports the acquisition of all manner of goods, products and materials produced in the United States, with a particular focus on steel, iron and manufactured goods. While discussions between Canada and the United States about the full implications of the order remain outstanding, to the extent the United States government procures oil and gas products or provides financial assistance to U.S. oil and gas producers, the order indicates that the United States will favour domestic production over foreign (including Canadian) producers and products, subject to applicable law.

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 impacts of the COVID-19 pandemic, 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 description 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 2021 was 15% for active business income, including resource income. The average provincial income tax rate for Suncor in 2021 was approximately 9.24%, resulting in a total Canadian income tax rate of approximately 24.24%.

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 2021 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 the 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, production sharing contracts 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 Regulations

The company is subject to environmental regulations 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 products and the byproducts associated with the production thereof, which apply to Suncor and similar activities conducted by other organizations. 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, refining, as well as electricity generation, 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 new laws and amendments to existing 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 regulators that oversee oil and gas development for comment by stakeholders, including industry. These statutes, regulations and frameworks relate to issues such as tailings management, water management, biodiversity, air emissions and land use. The company is committed to working with the appropriate government agencies as new policies are developed, and to comply with all existing and new statutes, regulations and frameworks that apply to the company's operations.

In general, the impact of future environmental laws and regulations on the company remains uncertain. It is not possible to predict the nature of any future legislative requirements or the impact that these 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, installing new emissions abatement equipment, treating fluid tailings, investing in renewable and low-carbon forms of energy, such as wind power, combined cycle co-generation, biofuels and hydrogen, undertaking land reclamation activities, investing in environmentally focused research and development, and working to advance 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 and GHG Emissions

Suncor operates in many jurisdictions that regulate, or have proposed to regulate, GHG emissions. Suncor is committed to complying with existing regulations and will continue to constructively engage the appropriate governmental bodies in dialogue to harmonize regulations focused on achieving reduction goals and sustainable resource development across jurisdictions where Suncor owns and/or operates assets.

As part of its ongoing business planning, Suncor estimates future costs associated with GHG 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. As of January 1, 2022, Suncor applies a carbon price of $50 per tonne of CO_2e, which will increase according to the recent federal government announcement described in the Industry Conditions – Climate Change and GHG Emissions – Canadian Federal GHG and Fuel Regulations – Under Development section of this AIF below. The company expects that GHG emissions regulation will continue to evolve with a carbon price that considers environmental, energy security, social and economic objectives.

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. Canada is a signatory to the agreement and Suncor supports the goals articulated in the Paris Agreement.

Canadian Federal GHG and Fuel Regulations

In furtherance of its commitments under the Paris Agreement, the federal government developed the *Pan-Canadian Framework on Clean Growth and Climate Change* (PCF) in 2016. To give effect to the PCF, the federal government introduced in 2018, the *Greenhouse Gas Pollution Pricing Act* (GGPPA). The GGPPA is 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: (i) an economy-wide consumer carbon levy on the use and combustion of fossil fuels; and (ii) an Output Based Pricing System (OBPS) applied to heavy industrial sectors that face international competition. The GGPPA's current application provincially is discussed below.

On March 25, 2021, in response to court challenges by the provinces of Alberta, Saskatchewan and Ontario regarding the federal government's authority to regulate carbon pricing, the Supreme Court of Canada concluded that the GGPPA is constitutional and the federal government has a right to impose national requirements for carbon pricing regulations.

Under the GGPPA, the federal government requires all provinces and territories to have a carbon price, which started at $20 per tonne of CO_2e in 2019 and has been rising by $10 per year to $50 per tonne of CO_2e in 2022. Building upon the PCF, the federal government announced its strengthened climate plan titled *A Healthy Environment and a Healthy Economy* in December 2020. Under the strengthened climate plan, the federal government proposed to increase the carbon price applied to both the GGPPA and the OBPS by $15 per tonne of CO_2e per year starting in 2023, rising to $170 per tonne of CO_2e in 2030. On August 5, 2021, the federal government published its update to *the Pan-Canadian Approach to Carbon Pollution Pricing 2023-2030* . The update and supporting information confirms: (i) Canada's annual national minimum carbon price increase of $15 per tonne of CO_2e per year starting in 2023; (ii) minimum

criteria for recognized provincial and territorial carbon pollution pricing systems; and (iii) provinces and territories that have carbon pricing systems meeting the minimum criteria, as well as an explanation of the tests used for assessments. The federal carbon pricing benchmark criteria to applicable industrial GHG emissions from 2023-2030 was also updated and the new expectations for increasing stringency were applied to provincial and territorial carbon pricing systems. Provinces and territories have the ability to customize their carbon pricing systems to maintain industrial competitiveness and achieve lowest cost to businesses and consumers.

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) a cap and trade system (adopted in Quebec). Within these programs, provinces have discretion to manage the 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.

Under the Federal *Impact Assessment Act*, the Strategic Assessment for Climate Change sets new requirements for GHG emissions reporting and planning for any projects governed under the *Impact Assessment Act*, including a requirement to provide a credible plan for relevant projects to deliver net-zero GHG emissions by 2050.

In addition to the above, the federal *Renewable Fuels Regulations* (RFR) implemented in 2010 under the *Canadian Environmental Protection Act, 1999* (CEPA) sets minimum renewable fuel content requirements in gasoline and diesel fuel sold to Canadian consumers. The regulations include provisions that govern the creation of compliance units, allow trading of these units among participants and require reporting to ensure compliance. In addition to the federal RFR, the provinces of Alberta, British Columbia, Manitoba, Ontario and Saskatchewan already have renewable fuel mandates equal to or greater than the current federal RFR.

Under Development

Pursuant to the Paris Agreement, the Government of Canada set a new goal to reduce GHG emissions economy-wide from 30% to 40%-45% below 2005 levels by 2030. The federal government has also passed the *Canadian Net-Zero Emissions Accountability Act*, which enshrines in legislation the legal requirement for the federal government to set national GHG emission reduction targets on a rolling five-year basis necessary to achieve net-zero emissions by 2050. This includes requirements to prepare plans and issue progress and assessment reports to ensure accountability.

Consistent with the *Canadian Net-Zero Emissions Accountability Act*, Prime Minister Trudeau announced on November, 1, 2021, at the COP 26 climate conference that Canada is the first major oil-producing country moving to capping and reducing emissions from the oil and gas sector by setting five-year targets to achieve net zero by 2050. In doing so, the government is seeking the advice of the Net-Zero Advisory Body on how best to work with the oil and gas sector and affected communities to define pathways to net-zero that are achievable, and can lead to a fairer, healthier and more prosperous future for all Canadians. Until the details of the Net-Zero Advisory Body's report are released and final regulations are published, it is not possible to estimate the precise impact this announcement may have on Suncor's business in Canada.

In addition to working with industries like the oil and gas sector to achieve Canada's net-zero emission goals, the federal government recently initiated consultations to support industries, workers and communities through the development of the *Just Transition* legislation. The aim of the legislation is to prepare workers to be able to fully participate in Canada's low-carbon economy vision as part of a global transition while seizing economic opportunities to support industries, workers and their communities. Until such legislation is published, the company is unable to predict the precise impact, if any, that Just Transition legislation will have on its business.

In the fall of 2020, the Government of Canada announced its intention to explore the potential of Border Carbon Adjustments (BCAs) as part of Canada's transition to a low-carbon economy. The federal government indicated, first in the 2020 Fall Economic Statement, and more recently in Budget 2021, that Canada would work with like-minded countries to consider how BCAs could fit into a broader strategy to meet climate targets in a manner consistent with maintaining Canada's competitiveness in a fair and open trading system. As government consultations are ongoing, the company is unable to predict the precise impact, if any, that BCAs will have on its business.

In addition to the GGPPA imposing an economy-wide consumer carbon levy on the use and combustion of fossil fuels, a Clean Fuel Regulation (CFR) is being developed by the federal government, which the government estimates will achieve annual reductions of at least 20 Mt of CO_2e emissions by 2030. The CFR will be implemented under CEPA and will replace the RFR. It is expected that the CFR will require reductions in the carbon intensity of liquid fuels supplied into Canada, based on a new life-cycle analysis model under development by the federal government. Credits for CFR will be given for lowering the carbon intensity of the fuel when it is consumed, as well as for reducing emissions during fuel production. Credits will also be provided for eligible fuel switching, such as supporting the deployment of electric vehicles or hydrogen fuel cell vehicles. The CFR is expected to be finalized in spring 2022 and come into effect in December 2022. Until such regulations are published, the company is unable to predict the precise impact, if any, that CFR will have on its business.

Provincial GHG and Fuel Regulations

Alberta

Oil Sands Emissions Limit Act

The *Oil Sands Emissions Limit Act* (OSELA) sets an emissions limit of 100 Mt of CO_2e per year in Alberta 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 between 70 to 80 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 it is therefore not yet possible to predict the long-term impact on Suncor.

Technology Innovation and Emissions Reduction Implementation Act

The *Technology Innovation and Emissions Reduction Implementation Act* (TIER) is a carbon pricing legislation for large industrial emitters that came into force on January 1, 2020. TIER meets the federal government's stringency benchmark criteria for large industrial emitters for 2021 and 2022. As a result, the federal OBPS applicable to large industrial emitters, described under GGPPA, will not apply to Alberta. TIER applies primarily 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, the Edmonton refinery and Syncrude. Such facilities were required to reduce emissions by 10% starting in 2020 with a further 1% per year reduction thereafter. Failure to meet emissions reduction targets results, either via performance or retiring eligible offsets or Emissions Performance Credits (EPCs), in being assessed at the prevailing carbon price on the remaining emissions. The carbon price under TIER increased from $40 per tonne of CO_2e in 2021 to $50 per tonne of CO_2e on January 1, 2022.

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 cogeneration facilities at its Oil Sands Base, Firebag, Fort Hills and Syncrude operations earn credits because the electricity generated is more efficient than the electricity standard.

Under TIER, each of Suncor's facilities is required to comply with the least stringent of either: (i) a facility-specific benchmark based on the average historical performance of that facility; or (ii) 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. Compliance obligations can be met by retiring eligible offsets or EPCs, or paying the prevailing carbon price. Offset credits can be generated by conducting eligible activities prescribed by provincial protocols. Suncor will continue to generate such credits from its cogeneration (EPCs) and renewable energy assets (offsets).

Federal RFR

The renewable fuel mandate in Alberta is governed by the federal RFR - refer to the Canadian Federal GHG and Fuel Regulations section.

Carbon Tax

In addition to the above, the federal carbon price under the GGPPA also applies to consumers' GHG emissions resulting from the combustion of fossil fuels consumed, for example, for heating and transportation. Carbon tax is applied at the prevailing federal carbon price to consumer fuel at the point of sale, which is later remitted to the federal government. Under the GGPPA, the carbon price increased from $40 per tonne of CO_2e in 2021 to $50 per tonne of CO_2e on January 1, 2022.

British Columbia

CleanBC Roadmap to 2030

CleanBC establishes a series of actions to put the province on a trajectory that would allow it to achieve its 2030 emissions reduction target and eventually its net-zero target by 2050. The actions included in the *CleanBC Roadmap to 2030* include: a commitment to increase the price on carbon to meet or exceed the federal benchmark, with supports for people and businesses; adoption of zero-emission vehicles (ZEVs) to 90% by 2030 and 100% ZEVs by 2035; the development of new ZEV targets for medium- and heavy-duty vehicles; increased clean fuel and energy-efficiency requirements (such as increasing stringency of the B.C. low carbon fuel standard from 20% carbon intensity reduction by 2030 to 30% and doubling the target for renewable fuels produced in B.C. to 1.3 billion liters by 2030); the completion of B.C.'s electric highway by 2024; a reduction of methane emissions from oil and gas by 75% by 2030 and the elimination of all industrial methane emissions by 2035; requirements for new large industrial facilities to work with B.C. government to demonstrate how they align with B.C.'s legislated targets and submit plans to achieve net-zero emissions by 2050; and support for innovation in areas like clean hydrogen, the forest-based bioeconomy and negative emissions technology.

B.C. Low Carbon Fuel Standard

In addition to the carbon tax, the Province of British Columbia is addressing transportation emissions through the *Greenhouse Gas Reduction (Renewable & Low Carbon Fuel Requirements) Act* and the *Renewable & Low Carbon Fuel Requirements Regulation*, known collectively as British Columbia's low carbon fuel standard (BC-LCFS). The BC-LCFS establishes annual carbon intensity reduction targets in gasoline and diesel fuels, which are achieved by blending renewable liquid fuels, as well as applying allowable credits. Suncor is partially able to flow through the BC-LCFS costs to consumers. On July 13, 2020, the Government of British Columbia amended the *Renewable & Low Carbon Fuel Requirements Regulation* to reduce the carbon intensity of fuels consumed from 10.2% in 2021 to 20% by 2030. Furthermore, the Province of British Columbia passed the *Zero-Emission Vehicles Act* (ZEV Act) on May 30, 2019. The ZEV Act requires automakers to meet an escalating annual percentage of new light-duty ZEV sales and leases, reaching 10% of light-duty vehicle sales by 2025, 30% by 2030 and 100% by 2040. The demand for low-carbon transportation options is expected to reduce the demand for gasoline and diesel, and increase the demand for renewable liquid fuels and electric vehicle charging.

B.C. Carbon Tax

In addition to the above, the provincial carbon price also applies to consumers' GHG emissions resulting from the combustion of fossil fuels consumed, for example, for heating and transportation. This carbon tax is applied at the published provincial carbon price to consumer fuel at the point of sale, legislated as a provincial sales tax, which is later remitted to the provincial government. Under the *Tax Rates for Fuel* bulletin, the effective carbon price, shown as a price per volume of fuel, will increase from $45 per tonne of CO_2e in 2021 to $50 per tonne of CO_2e on April 1, 2022.

Newfoundland and Labrador

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* and associated regulations, which apply to all facilities that emit 15,000 tonnes of CO_2e or more per annum and therefore apply to Terra Nova (when it is operating), Hibernia, White Rose and Hebron. Consistent with the federal carbon pricing scheme, the Newfoundland and Labrador carbon price in 2021 was $40 per tonne of CO_2e and has increased to $50 per tonne of CO_2e in 2022.

Offshore production facilities were assigned an annual GHG reduction target of 10% in 2021 and 12% in 2022 below the facility's 2016-17 historical average emissions-to-output ratio, excluding methane emissions from venting and fugitive sources.

Under Development

The *Management of Greenhouse Gas Act* established a fund to support energy-efficient and clean technology investments 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.

Ontario

Greenhouse Gas Emissions Performance Standards

In 2021, large emitters in Ontario were subject to the federal OBPS. As of January 1, 2022, the "made in Ontario" GHG Emissions Performance Standards (EPS) will supersede and replace the federal OBPS. Unlike the federal OBPS, which applied to facilities that generated more than 25,000 tonnes of GHG emissions per year (including Suncor's Sarnia refinery and St. Clair ethanol plant), the EPS applies to facilities that generate more than 50,000 tonnes of GHG emissions per year. Suncor does not expect any material changes to its business as a result of this change.

Cleaner Transportation Fuels Regulation

In 2020, the Government of Ontario announced the *Cleaner Transportation Fuels Regulation* revoking and replacing the *Greener Gasoline Regulation* and *Greener Diesel Regulation* under the *Environmental Protection Act*. The new regulation increases the renewable content in gasoline and provides new technical guidelines to support the provincial government's goal of reducing GHG emissions by 30% below 2005 levels by 2030 as set out in the Made-in-Ontario Environment Plan.

Carbon Tax

In addition to the above, the federal carbon price under the GGPPA also applies to consumers' GHG emissions resulting from the combustion of fossil fuels consumed, for example, for heating and transportation. Carbon tax is applied at the prevailing federal carbon price to consumer fuel at the point of sale, which is later remitted to the federal government. Under the GGPPA, the carbon price increased from $40 per tonne of CO_2e in 2021 to $50 per tonne of CO_2e on January 1, 2022.

Quebec

Implemented in 2013, Quebec's cap-and-trade system for GHG emissions applies to companies in the industrial and electricity combustion sectors that emit 25,000 tonnes or greater of CO_2e per year and distributors of fossil fuels used in Quebec. Quebec's cap-and-trade system is linked to California's and is part of the Western Climate Initiative (WCI), an organization set up to help members in U.S. states and Canadian provinces execute their cap-and-trade systems. Allowances and offsets are tradeable across the WCI. In Quebec, emitters are required to either reduce their emissions or purchase eligible emissions allowances to cover their emissions beyond any free emissions allowances they receive from the government. The cap on overall annual GHG emissions and the maximum amount of free allowances allocated to regulated emitters are established by the province. The emissions at Suncor's Montreal refinery are subject to Quebec's cap-and-trade system, while the Montreal Sulphur Plant is a voluntary participant of the cap-and-trade system. The cost to purchase emissions allowances under the cap-and-trade system associated with consumer fuel purchases is passed on to consumers at the point of purchase.

Under Development

In September 2021, the Government of Quebec started consultations on its cap-and-trade system for the 2024-2030 compliance period. The final regulation is expected to be released in Q1 2022. The changes may include an annual decline of the facility-specific emissions cap of 3.7%, compared to the current 1%. The additional funds collected from the increased compliance costs would be set aside and available to the regulated industrial site to invest in GHG reduction projects and other emerging low-carbon-intensity technologies.

In the fall of 2020, the Quebec government introduced its *2030 Plan for a Green Economy* to help achieve its 2030 GHG emissions reduction target, namely a 37.5% reduction compared with 1990 levels, and to reach carbon neutrality by 2050. With respect to renewable fuel content, the plan contemplates requiring the blending of a minimum volume of 15% of ethanol into gasoline and a minimum volume of 10% bio-based diesel into diesel fuel by 2030. The plan will include a mandate to phase out the sale of new gasoline-powered vehicles by 2035. The rate of change of consumer behaviour, such as the adoption of ZEVs or increased use of public transit or active transportation, is not certain. The demand for low-carbon transportation options is expected to reduce the demand for gasoline and diesel and increase the demand for renewable liquid fuels and electric vehicle charging.

On May 5, 2021, the Government of Quebec published the *Draft Regulation Respecting the Integration of Low Carbon-Intensity Fuel Content into Gasoline and Diesel Fuel* with the intent to phase in a requirement by 2030 to reduce the carbon intensity of gasoline by up to 15% and diesel by up to 10%. The standards are intended to take effect on January 1, 2023.

U.S. GHG Regulations

The U.S. Environmental Protection Agency (U.S. EPA) has established a rule mandating that all large facilities (defined as facilities emitting greater than 25,000 tonnes of CO_2e per year, which includes Suncor's refinery in Commerce City, Colorado) 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; and to transition Colorado's electricity system to become 80% renewable by 2030 and 100% renewable by 2040. The legislation requires several regulations to be adopted through rulemakings to support implementation, which will address, among other things, reducing GHG emissions from the oil and gas sector, the industrial and manufacturing sector and other sectors, and requirements to monitor, measure and report GHG emissions.

In 2021, the State of Colorado passed a law (HB 21-1266) that requires the industrial and manufacturing sector as a whole, which includes refining, to reduce 2030 GHG emissions by 20% using a 2015 baseline. However, energy-intensive trade exposed (EITE) manufacturing facilities that currently employ GHG best available emission control technologies and best available energy efficiency practices, are required to reduce GHG emissions by 5%. The Commerce City refinery is currently not designated as an EITE facility.

Colorado is expected to adopt GHG regulations through rulemakings for non-EITE facilities in the industrial and manufacturing sectors in 2022 or 2023.

The impact on Suncor, including its Commerce City refinery, is unknown at this time.

Under Development

President Biden's administration has confirmed its commitment for the U.S. to rejoin the Paris Agreement. As part of this commitment, President Biden announced that the U.S. will reduce GHG emissions from 2005 levels by 50-52% by 2030. The President has also committed to creating a carbon-pollution-free power sector by 2035 and reaching net-zero emissions economy-wide by 2050. To meet these climate commitments, the President is expected to use his executive authority to re-establish standards for power plant emissions, reform vehicle efficiency standards, re-establish methane emissions limits and integrate climate change into foreign and trade policy and national security strategies. In addition, the United States Climate Alliance, a network consisting of the governors of 25 states, which includes 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 Norway assets in 2021. Suncor's U.K. non-operated assets are subject to the U.K. Emissions Trading Scheme (UK ETS). Each of the EU ETS and UK ETS work on a cap-and-trade principle, requiring the setting of emission limits for the sectors covered by the scheme. Each year, emissions allowances equivalent to the cap are either auctioned or distributed as free allowances to participants. A secondary market is also available for participants to buy and sell allowances from each other. Each year, regulated facilities surrender emissions allowances to cover their reportable emissions. The emissions cap is reduced over time to reduce total emissions. Both the EU ETS and UK ETS have mechanisms to effectively establish floor and ceiling prices to manage the cost of credits.

Compliance Costs

The following table outlines the costs associated with the GHG emissions policies for the company's equity share of operated assets:

Reporting Segment ($ millions)	2020	2021(4)	2022 (Estimate)
Oil Sands(1)	27.4	81.9	93.2

Exploration and Production[2]	nil	nil	nil
Refining and Marketing[3]	10.8	15.6	22.0

(1) Compliance costs for Suncor are increasing under TIER for mining facilities due to the increase in stringency of the facility benchmarks and rise in prevailing carbon prices. Refer to the TIER section above.

(2) Forecast compliance costs are nil due to Terra Nova not expected to be back online until the fourth quarter of 2022, and emissions projected to be below the facility benchmark.

(3) Compliance costs are increasing over time based on the increasing GHG cost per tonne and decreasing GHG emissions targets per federal and provincial regulations.

(4) A portion of 2021 costs are based on estimates and may differ from actuals that will be finalized upon later settlement of compliance costs.

Land Use and Natural Resources Management Frameworks

Canadian Land Use and Natural Resources Management

Alberta Land Use and Water Management Regulatory Frameworks

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 land leases owned or operated by Suncor or its affiliates.

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 land and natural resources management on a regional scale. As a result, LARP may require Suncor or its affiliates to have greater participation in the overall evaluation of environmental issues and air emissions in the Lower Athabasca region. The frameworks established under LARP include the following:

- **Surface Water Quality Management Framework for the Lower Athabasca River.** This framework provides a basis with which to monitor and manage long-term, cumulative changes in water quality within the Lower Athabasca River. The framework includes quality limits and triggers for various indicators, based on existing guidelines from the Alberta provincial government, Canadian Council of Ministers of the Environment, Health Canada and the U.S. EPA. Regulatory and/or management actions will occur when triggers or limits are reached or exceeded.

- **Surface Water Quantity Management Framework.** This framework 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. 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 that is submitted to Fisheries and Oceans Canada and Alberta Environment and Parks as required by the framework.

- **Groundwater Management Framework.** The Groundwater Management Framework aims to manage non-saline groundwater resources in a sustainable manner and protect groundwater resources from contamination and overuse. 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.** The Tailings Management Framework (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, effective 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.

The Alberta government has also been working to update the provincial water release policy tools, and the updates are expected to be completed in 2023. In addition, work to develop a federal Oil Sands Mine Effluent Regulation (OSMER) is ongoing with Environment and Climate Change Canada (ECCC), with a hope that the regulation will be finalized by 2025. If implemented, OSMER is expected to assist companies with returning treated water to the Athabasca River.

Air Quality Regulations

Air quality in Suncor's operating areas is an increased focus and has resulted in the introduction and/or update of policy/regulations of air pollutants, odours and health standards to drive performance improvement. Overall, regulators are moving toward setting new, more stringent limits often requiring updating or replacement of equipment, and additional monitoring and reporting requirements. Air quality regulations impacting Suncor's Canadian operations are listed below:

- The LARP discussed in the Land Use and Natural Resources Management section also includes the 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 and/or management actions will occur when triggers or limits are reached or exceeded.

- Canadian Ambient Air Quality Standards (CAAQS) – In October 2012, the Canadian Council of Ministers of the Environment, with the exception of Quebec, agreed to implement a new Air Quality Management System. One of the key elements of the system is the ambient air quality objectives for selected air pollutants set out under the CEPA, which include limits for fine particulate matter (PM 2.5) and ground-level ozone implemented in 2015 and updated in 2020. New standards for NO_2 and SO_2 were developed and became effective in 2020. It is a provincial responsibility to ensure implementation of the nationwide standards of CAAQS are achieved. All of Suncor's Canadian operations, with the exception of the Montreal refinery, will be impacted by CAAQS and work is underway to meet the ambient air quality standards for both monitoring and regulatory applications. The impacts are highest for the operations located in airsheds that are likely to exceed CAAQS limits, including areas such as the Wood Buffalo Region (Oil Sands Base, Fort Hills, Firebag, MacKay River and Syncrude), the Edmonton region (Edmonton refinery) and the Sarnia region (Sarnia refinery and St. Clair ethanol plant).

- Alberta Ambient Air Quality Objectives (AAAQO) – AAAQO and guidelines are issued by Alberta Environment and Parks under Section 14 (1), of the *Environmental Protection and Enhancement Act*. AAAQO are developed to protect Alberta's air quality and are used as part of industrial approvals to regulate facility operations. All industrial indoor and outdoor facilities must be designed and operated such that the ambient air quality remains below AAAQO. Alberta Environment and Parks is currently reviewing NO_2 and SO_2 AAAQO in light of the 2020 CAAQS, which could have significant cost implications for Suncor's operations in Alberta.

- Methane Regulations – The Canadian federal government, through the ECCC, and the Government of Alberta have both released new methane regulations. The federal regulations came into effect in January 2020, to fulfil Canada's commitment to reduce methane emissions from the upstream oil and gas sector by 40% to 45% below 2012 levels by 2025. On November 11, 2020, the Government of Alberta reached a formal equivalency agreement with ECCC, which will replace the federal regulations for up to five years. Alberta's Methane Emission Reduction Regulation will impact Suncor's In Situ operations in Alberta through changes to the measurement, monitoring and reporting of methane emissions to support improved understanding and tracking of oil and gas methane emissions. Similar equivalency agreements to the federal methane regulations are also in effect in British Columbia and Saskatchewan, which have their own regimes. ECCC recently published a methane regulation review report; Environment Canada acknowledged that the upstream oil and gas sector is on track to achieve the 2025 methane reduction target. However, Canada revised its methane reduction goal in October 2021, in support of the Global Methane Pledge, committing to reducing oil and gas sector methane emissions by at least 75% below the 2012 level by 2030. This revised methane emissions reduction target is expected to incur an added cost for Suncor In Situ operations to comply with the additional emission reduction requirements.

- Volatile Organic Compound (VOC) Regulations for Upgrading & Refining – *Reduction in the Release of Volatile Organic Compounds Regulations (Petroleum Sector)* comes into effect on January 1, 2022, and will limit the release of VOCs, including carcinogenic substances such as benzene and 1,3 butadiene, by requiring Canadian refineries and upgrader facilities to take measures to reduce leaks from equipment components (valves, pumps, connectors, etc.). This regulation requires facilities to conduct leak detection and repairs on their equipment, as well as monitor VOC concentrations at the facility perimeter. Suncor will incur costs to comply with the requirements but will also recover products that would otherwise have been lost from leaking equipment components.

- Ontario regulations for addressing sulphur dioxide emissions – The *Addressing sulphur dioxide emissions from Ontario's petroleum facilities* draft regulation was published in November 2021 for comment. This regulation would require SO_2 emissions reductions from Sarnia refinery, under normal operation as well as maintenance and upset conditions. The refinery already includes many of the best practices in terms of SO_2 reduction, and it is working with Aamjiwnaang First Nation, Walpole Island First Nation and the Ministry of the Environment, Conservation and Parks towards additional SO_2 emissions reduction.

U.S. Land Use and Natural Resources Management

Water Management Regulations

The Commerce City refinery's water discharge permit is currently subject to a renewal process. In late 2021, the Water Division for the Colorado Department of Public Health and Environment issued a draft water permit, which contains new and additional proposed requirements, including with respect to those related to per- and polyfluoroalkyl substances, that could impose an additional financial impact on the company. Suncor is reviewing the draft permit and will proceed through the permit renewal process.

Air Quality Regulations

Air quality in Suncor's U.S. operating areas is an increased focus and has resulted in the introduction and/or update of policy/regulations of air pollutants, odours and health standards to drive performance improvement. Overall, regulators are moving toward setting new, more stringent limits often requiring updating or replacement of equipment, and additional monitoring and reporting requirements. Air quality regulations impacting Suncor's U.S. operations are listed below:

- Colorado *House Bill 21-1189 (Concerning Additional Public Health Protections in Relation to the Emission of Air Toxics)* – This bill, which was signed into law in 2021, amended prior legislation passed in 2020 (Colorado *House Bill 20-1265*). The original law created a new category of covered air toxics (hydrogen cyanide, hydrogen sulfide and benzene), a new category of covered facilities defined by reporting certain thresholds of any of the covered air toxics, and required such facilities to conduct community outreach regarding incident communications and implement the use of an emergency notification service for certain incidents. The new law redefined the covered facilities by NAICS code, requires the facilities to conduct real-time fenceline monitoring for covered air toxics, and requires the Colorado Department of Public Health and Environment to conduct community air monitoring to be paid for by the covered facilities. This will increase monitoring and reporting requirements for Suncor's Commerce City refinery.

- U.S. Regional Haze State Implementation Plan Revisions and Regulation 23 Development – The Regional Haze Rule under the EPA calls for state and federal agencies to work together to improve visibility in national parks through addressing the primary pollutants that cause regional haze, including particulate matter, NOx and SO_2. Emission sources from industry include heaters/boilers, fluid catalytic cracking units and sulphur recovery complexes. Improvements to one of the sulphur recovery units at Suncor's Commerce City refinery will be required to meet this regulation.

- In 2021, Colorado conducted a rulemaking to conduct revisions to Regulation 7 (Controls of Ozone via Ozone Precursors and Control of Hydrocarbons via Oil and Gas Emissions), including requirements to implement NOx Reasonably Available Control Technology for process heaters at major sources. Certain of these rule revisions will apply to the Commerce City refinery.

- Title V air operating permits, under the federal *Clean Air Act,* apply to the Commerce City refinery's East and West plants, which are undergoing permit renewal applications. In 2021, Suncor participated in public comment sessions and responded to public comment with respect to its East Plant Title V air operating permit renewal application. In 2022 or 2023, Suncor expects a similar process to be conducted with respect to its West Plant Title V air operating permit renewal application.

Biodiversity

Governments are increasing the rigour of existing acts/regulations and issuing changes aimed at improved environmental protection, including habitat and species protection. Policy development and engagement is complex. Stakeholders are concerned by the slow progress by government to protect habitat. In addition, traditional land use rights of Indigenous communities are inclusive of caribou herds and the issue of caribou habitat is often a recurring theme in Statements of Concerns during the regulatory process. Within the Wood Buffalo region, an area with more than ~40% wetland cover, many of Suncor's current and future projects are within identified caribou ranges.

In October 2020, Alberta Environment and Parks and ECCC announced they had finalized a *Species at Risk Act* (SARA) Section 11 Conservation Agreement for Alberta's caribou populations. The agreement identifies timelines for the Alberta sub-regional planning process and establishes the collaborative responsibilities of the provincial and federal governments. The first sub-regional plan within the oil sands region is expected to be finalized in 2022. Under this agreement, industry will continue to work with the Government of Alberta as part of the sub-regional planning process.

The Alberta Wetland Policy has been in effect province-wide since July 2016. The Policy's goal is "to conserve, restore, protect and manage Alberta's wetlands." For certain new project types, an upfront detailed wetland assessment must be performed for all surface disturbances. Under the policy, where avoidance and minimization efforts are not feasible or prove ineffective, wetland replacement is required at a ratio determined by wetland value from 1:1 to 8:1. Wetland replacement costs will be especially high for future oil sands projects and expansions, since there is limited to no opportunity to avoid or minimize impacts to wetlands. Suncor continues to work with the Government of Alberta to resolve any ongoing implementation challenges.

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. These updates apply to all dams in Alberta. 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. A regulatory tool shared by the AER was 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.

These regulations are being implemented through Suncor's internal programs that aim to provide compliance and additional oversight in accordance with industry-leading guidelines. The Mining Association of Canada's (MAC) *Guide to Management of Tailings Facilities* and the Canadian Dam Association's (CDA) *Dam Safety Guidelines*, and their associated technical bulletins are considered leading practice guidelines worldwide. In August 2020, the *Global Industry Standard for Tailings Management* (GISTM) was issued at the international level to raise the level of diligence for tailings dams around the world, with particular attention to old and deteriorating dams. The GISTM also provides principles of practice for all new dams going forward. MAC and CDA have worked to gain additional alignment with the GISTM. Suncor operations are in alignment with the principles and requirements through commitments to AER regulations, as well as MAC and CDA guidelines. Additionally, Suncor has worked with MAC and CDA to gain alignment between their respective guidelines and the GISTM.

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. 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

Suncor is committed to surface reclamation and remediation of lands affected by its operations. The Government of Alberta's Mine Financial Security Plan (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, falling below a specified asset to liability ratio, 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 by 2023.

Suncor has improved its tailings management efforts and became the first company to surface reclaim an oil sands tailings pond, convert a second pond to a fluid tailings treatment area, and make another pond trafficable with coke capping. Under the TMF, initial tailings management plans have been submitted and approved for Suncor Base Plant (2017), Syncrude Aurora North (2018), Syncrude Mildred Lake (2019)

and Fort Hills (2019), although further submissions and approvals will be required before carrying out these plans.

Another component identified in the TMF is integrated water management. In order to support successful closure and reclamation, Suncor believes water quantity must be reduced, and quality must be managed. The Alberta government has been working to update the provincial water release policy tools and the updates are planned to be completed in 2023. The five-year review for the TMF is planned for 2022, which will have the potential to significantly impact progress on fluid tailings management, water release and all associated aspects of TMF implementation, such as pit lakes, closure and reclamation, and the MFSP.

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 annual cost to Suncor under the Monitoring Plan, including Suncor's net share of Syncrude, was $11.3 million for 2021, which will be paid in early 2022. A continued focus on governance and planning is important for the program to achieve its objectives.

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. Similarly, Suncor is a founding member of the Clean Resource Innovation Network (CRIN), which is a pan-Canadian network focused on ensuring Canada's energy resources can be sustainably developed and integrated into the global energy supply. CRIN identifies industry challenges to accelerate clean technology commercialization and widespread adoption by bringing together a broad group of stakeholders. Moreover, Suncor is an originating sponsor of the Carbon XPRIZE aimed at developing breakthrough technologies to convert GHG emissions into usable products. In June 2021, Suncor, along with other oil sands companies, announced the Oil Sands Pathways to Net Zero initiative. The goal of this alliance, working collectively with the federal and Alberta governments, is to achieve net zero GHG emissions from the companies' oil sands operations by 2050, to help Canada meet its climate goals, including its Paris Agreement commitments.

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 electricity 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, decisions by OPEC+ regarding quotas on its members, compliance or non-compliance with quotas agreed upon by OPEC+ members and other countries, and weather. Many of the factors that can cause volatility have been, and may continue to be, affected by the impacts of the COVID-19 pandemic. 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, regulatory compliance costs and other local market factors. Natural gas prices in North America are affected by, among other things, supply and demand, inventory levels, weather and 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.

Wide differentials 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.

Commodity prices could be materially and adversely affected by the outbreak of epidemics, pandemics and other public health crises in geographic areas in which Suncor has operations, suppliers, customers or employees, including the COVID-19 pandemic and the ongoing uncertainty as to the extent and duration of the pandemic, as well as uncertainty surrounding new variations or mutations of the COVID-19 virus. Actions that have and may be taken by governmental authorities in response to the ongoing COVID-19 pandemic have resulted, and may continue to result in, among other things, increased volatility

in commodity prices. In particular, the COVID-19 pandemic has resulted in, and may continue to result in, a reduction in the demand for, and prices of, commodities that are closely linked to Suncor's financial performance, including crude oil, refined petroleum products (such as jet fuel and gasoline), natural gas and electricity, and also increases the risk that storage for crude oil and refined petroleum products could reach capacity in certain geographic locations in which we operate. While vaccines are being distributed, there is uncertainty as to the timing, level of adoption, duration of efficacy and effectiveness of vaccines against current or future variants or mutations. This continues the risk and uncertainty as to the extent and duration of the COVID-19 pandemic and the resultant impact on commodity demand and prices. A prolonged period of decreased demand for, and prices of, these commodities, and any applicable storage constraints, could also result in us voluntarily curtailing or shutting in production and a decrease in our refined product volumes and refinery utilization rates. Additionally, commodity prices could remain under pressure for a prolonged period. This could result in reduced utilization and/or the suspension of operations at certain of our facilities, buyers of our products declaring force majeure or bankruptcy, the unavailability of storage, and disruptions of pipeline and other transportation systems for our products, which would further negatively impact Suncor's production or refined product volumes, and could have a material adverse effect on Suncor's business, financial condition, reserves and results of operations.

Carbon Risk

Public support for climate change action and receptivity to alternative or 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 in support of a transition to low-carbon energy and climate change action may impose significant constraints on fossil fuel development. 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. These risks to the oil sands industry can be offset over time through the commercialization and implementation of low-carbon technologies (e.g., carbon capture, utilization and sequestration) and by increasing growth in low-carbon energies such as hydrogen, renewable fuels and power.

Changes to environmental regulations, including regulations relating to climate change, could impact the demand for the company's products or could require increased capital expenditures, operating expenses, abandonment and reclamation obligations, and distribution costs. These potential added costs may not be recoverable in the marketplace and may result in some current operations or growth projects becoming less profitable or uneconomic. Such regulatory changes could require Suncor to invest further into the development of technologies or other energy products. Such technology development or growth projects could require a significant investment of capital and resources, and any delay in or failure to identify, develop and deploy such technologies or obtain regulatory approvals for these technology projects could prevent Suncor from being able to successfully compete with other companies. More stringent GHG emissions regulations in the jurisdictions in which Suncor operates may also make it difficult for Suncor to compete with companies operating in other jurisdictions with 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 petroleum products, and could result in delayed development, stranded assets or the company being unable to further develop its hydrocarbon resources. The complexity, breadth and velocity of changes in GHG emissions regulations make it difficult to predict the potential impact to Suncor.

Suncor continues to monitor international and domestic efforts to address climate change. While GHG regulations and targets will continue to become more stringent, and while Suncor continues its efforts to

reduce its GHG emissions, the absolute operational GHG emissions of the company may rise as a result of growth, mergers and acquisition activities, and changes in the operatorship of assets by Suncor or affiliates, which is particularly relevant in 2021 given that Suncor assumed operatorship of Syncrude in 2021. 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 and the federal government's stated intention to cap and reduce emissions from the oil and gas sector by setting five-year targets to achieve net zero by 2050 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 and GHG Emissions – 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.

Greenhouse Gas Emissions and Targets

Among other sustainability goals, Suncor has set a strategic objective of net-zero emissions by 2050 and a target to reduce GHG emissions through our value chain by 10 Mt by 2030. Our ability to deliver GHG emissions reductions 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, development and deployment of new technologies, ability to sequester and capture carbon, investment in low-carbon power and hydrogen, as well as a 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 on the current timelines, or at all.

In addition, achieving our GHG emissions reduction targets 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, and these differences may be material. In addition, while the intent is to improve efficiency and increase the offering of low-carbon energy, 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 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.

Environmental Compliance

Tailings Management and Water Release

Each oil sands mine is required under the AER's 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 and reclamation, 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 Natural Resources Management section of this AIF.

The five-year review for the TMF (discussed in the Industry Conditions – Environmental Regulation – Reclamation section of this AIF) is planned for 2022, which will have the potential to significantly impact progress on fluid tailings management and water release, as well as all associated aspects of TMF implementation, such as pit lakes, closure and reclamation, and the MFSP. The Alberta government has also been working to update the provincial water release policy tools and the updates are expected to be completed in 2023. In addition, work being done to develop the Federal OSMER is ongoing with ECCC (refer to the Industry Conditions – Environmental Regulation – Land Use and Water Management section of this AIF). If implemented, OSMER is expected to assist companies with returning water to the Athabasca River.

The review of the TMF may result in changes to the TMF that are adverse to Suncor. In addition, there can be no assurances that the provincial water release policy tools or OSMER will be updated or implemented, as the case may be, in accordance with expected timelines, if at all, or that if updated or implemented, they will permit Suncor to release water to the environment as required to support successful closure and reclamation.

In order to support successful closure and reclamation, Suncor supports an integrated water management approach for effective operations, successful reclamation and closure, and positive environmental outcomes. The inability to release sufficient water to the environment continues to result in an increase to both water quality concerns and water containment concerns at Suncor mine sites, which impacts current operations and reclamation and closure planning. Suncor believes that 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. The absence of an effective regulatory framework in this area could impact operations and 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

The implementation of, and compliance with, the terms of the Alberta's Land-Use Framework through the Lower Athabasca Regional Plan (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, and/or any updates or changes to the LARP, could have a material adverse effect on Suncor's business, financial condition, reserves and results of operations.

Alberta Environment and Parks Water Licences

Suncor currently relies on water obtained under licences from Alberta Environment and Parks 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, any changes or expansions 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. Refer to the Industry Conditions – Environmental Regulation – Land Use and Natural Resources Management section of this AIF.

Commerce City Refinery Water Permit

The Commerce City refinery's water discharge permit is currently subject to a renewal process. New and additional proposed requirements, including those related to per- and polyfluoroalkyl substances, could have a material adverse effect on Suncor's business, financial condition and results of operations. Refer to the Industry Conditions – Environmental Regulation – Land Use and Natural Resources Management – U.S. Land Use and Natural Resources Management section of this AIF.

Biodiversity

Species at risk exist in the areas where Suncor owns and operates its leases. For example, 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 through sub-regional planning. Suncor has existing, planned and potential future projects within caribou ranges in Alberta. The development and implementation of sub-regional plans in these areas may have an impact on the pace and amount of development in these areas and could potentially increase costs due to restoration or offsetting requirements, which could have a material adverse effect on Suncor's business, financial condition, reserves and results of operations.

Pursuant to the Alberta Wetland Policy, development in wetland areas may be obligated to avoid wetlands or mitigate the development's effects on wetlands. 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. Refer to the Industry Conditions – Environmental Regulation – Biodiversity section of this AIF.

Air and Water Quality Management

A number of Canadian federal, provincial and U.S. federal and state air and water quality regulations and frameworks are in place currently and being developed, changed and/or implemented, which could have an impact on the company's existing operations and planned projects including by, among other things, 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. Refer to the Industry Conditions – Land Use and Natural Resource Management section of this AIF.

Market Access

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 oil, 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. In order to secure future market access, financial commitments could be made for projects that do not proceed. 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, 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 poor or substandard 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, among others, oil spills, gaseous leaks or a release of deleterious substances, loss of tailings dam integrity, 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 cyberattacks.

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.

Suncor is also subject to risks relating to the health and safety of our people, as well as the potential for a slowdown or temporary suspension of our operations in locations impacted by an outbreak such as the COVID-19 pandemic. Such a suspension in operations could also be mandated by governmental authorities in response to the COVID-19 pandemic. This could negatively impact Suncor's production or refined product volumes and refinery utilization rates for a sustained period of time, all of 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, 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 Policy

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 such as the mandatory production curtailments imposed by the Government of Alberta in 2019 and 2020), environmental protection, water, wildlife, fish, air quality, 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 (temporarily or permanently), 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 certain projects, including 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, government intervention, environmental impact assessments and public hearings 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, impacts to production, reputational damage 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 the revocation of existing approvals or permits by the government 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.

Digital and Cybersecurity

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 cybersecurity 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. 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 cyberattack to, or breach of, its information technology and infrastructure.

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, 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.

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 and may result in property damage. Outcomes of such incidents 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 and E&P businesses, 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.

Portfolio Development and Execution

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

Portfolio 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.

Portfolio development and execution can also be impacted by, among other things, the effect of changing government regulations 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 complexity and diversity of Suncor's portfolio, including joint venture assets; the accuracy of project cost and schedule estimates; 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; 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 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

To achieve its business objectives, Suncor 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 it may negatively impact the company should there be inadequate consideration of the cumulative impacts of prior and parallel initiatives on people, processes and systems. There is a risk that measures undertaken to achieve 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.

Skills, Resource Shortage and Reliance on Key Personnel

The successful operation of Suncor's businesses 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 and retaining the skilled labour in certain talent segments for current and future operations. Although Suncor has maintained a healthy overall attrition rate over the last decade, Suncor sees acute supply-demand gap potential in some critical talent segments. The labour market is also in flux, which combined with the challenges recruiting to our industry and post-pandemic trend of burnout and employees reassessing their careers, increases the potential risk in attrition and the need for targeted talent remains a risk to be managed. The increasing age of the company's existing workforce, and changing skillset requirements as technology continues to evolve, add 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 or due to supply chain disruptions related to the COVID-19 pandemic. 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 Suncor's business, financial condition, reserves and results of operations. 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 and Fort Hills), all of the company's refineries and the majority of the company's terminal and distribution operations and certain of the company's E&P operations are represented by labour unions or employee associations. Approximately 25% of the company's employees were covered by collective agreements at the end of 2021. Negotiations for four collective agreements will take place in 2022. Any work interruptions involving the company's employees (including as a result of a strike, lockout or pandemic), 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.

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 and arrangements where Suncor operates assets in which other entities have 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 and operating expenditure 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

Access to Capital

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, if needed, 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. Investors and stakeholders increasingly compare companies based on climate-related performance. Failure to achieve the company's net-zero and GHG emissions reduction targets and goals, or a

perception among financial institutions and investors that such targets and goals are insufficient, could adversely affect the company's reputation and ability to attract capital. The company's ability to access capital may also be adversely affected in the event that financial institutions, investors, rating agencies and/or lenders adopt more restrictive decarbonization policies. The COVID-19 pandemic had a significant impact on global capital markets and the availability of liquidity. While access to capital has returned to pre-pandemic levels, the disruption and volatility in global capital markets may re-occur. 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 nor its bylaws 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, and the level of indebtedness relative to the company's ability to generate cash flow, 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 applicable 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 some commodity sales or purchase transactions or those 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.

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, unfavourable movements in commodity prices, interest rates or foreign exchange that could result in a financial or opportunity loss to the company; a lack of counterparties, due to market conditions or other circumstances that could leave the company unable to liquidate or offset a position, or unable to do so at or near the previous market price; and counterparty default risk.

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 2021 audited Consolidated Financial Statements are presented in Canadian dollars. 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, while the majority of Suncor's expenditures are realized in Canadian dollars. Suncor also has assets and liabilities, including approximately 60% of the company's debt, that are denominated in U.S. dollars and translated to Suncor's reporting currency (Canadian dollars) at each balance sheet date. 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, 2021, the Canadian dollar strengthened in relation to the U.S. dollar to $0.79 from $0.78 at the start of 2021. 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, which are off-setting exposures to some degree. Suncor may also be exposed to higher interest rates 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 if derivative instruments are used to manage the debt portfolio. Unfavourable changes in interest rates could have a material adverse effect on Suncor's business, financial condition and results of operations.

Royalties and Taxes

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

Royalties can be impacted by changes in crude oil and natural gas pricing, production volumes, sales volumes, and capital and operating costs, by changes to existing legislation or production sharing contracts, 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, 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 prevailing business environment, 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, 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, terrorism, war, insurrection, and geopolitical and other political risks; increases in taxes and government royalties; compliance with existing and emerging anti-corruption laws, including the *Corruption of Foreign Public Officials Act* (Canada), the *Foreign Corrupt Practices Act* (United States), and *Bribery Act* (United Kingdom); 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.

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 increased in recent years, and the Canadian federal government and the provincial government in Alberta have committed to renew their relationships with the Indigenous Peoples of Canada. In particular, the federal government has stated it fully supports the United Nations Declaration on the Rights of Indigenous Peoples (the Declaration). On December 3, 2020, the federal government introduced Bill C-15, *An Act respecting the United Nations Declaration on the Rights of Indigenous Peoples* (Bill C-15), as a means of adopting the Declaration into Canadian law while stating that the legislative framework will "ensure sustained and continued efforts to uphold the rights of Indigenous Peoples now and in the future." On June 21, 2021, Bill C-15 received Royal Assent. For its part, Suncor stated support for Bill C-15. At the same time, Suncor also expressed a desire for the government to clarify the ambiguity around Bill C-15 and to provide clear guidelines. Given Bill C-15's recent adoption, it is unknown how Bill C-15 will ultimately be implemented and interpreted as a part of Canadian law, and it therefore also remains unclear what its corresponding impact will be on the Crown's duty to consult with Indigenous Peoples.

At this point Suncor is unable to assess the effect, if any, that any such land claims, consultation requirements with Indigenous Peoples or the implementation of Bill C-15 into Canadian law may have on Suncor's business; however, the impact could have a material adverse effect on Suncor's business, financial condition, reserves and results of operations.

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.

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 $0.42 per common share in each quarter of 2019, a quarterly dividend of $0.465 per common share in the first quarter of 2020, a quarterly dividend of $0.21 per common share in the remaining quarters of 2020 and the first three quarters of 2021 and a quarterly dividend of $0.42 per common share in the fourth quarter of 2021. Dividends are paid subject to applicable law, if, as and when declared by the Board.

Year ended December 31	**2021**	2020	2019
Cash dividends per common share ($)	1.05	1.10	1.68

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, 2021, there were 1,441,250,800 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 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 by the rating agencies noted herein as of February 23, 2022. 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)	BBB+	Negative	A-1 (low)	A-2
Dominion Bond Rating Service (DBRS)	A (low)	Stable	R-1 (low)	Not rated
Moody's Investors Service (Moody's)	Baa1	Stable	Not rated	P-2

(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 is rated BBB+ (negative) by S&P. Moody's and DBRS do 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 BBB+ by S&P is the fourth highest of 10 categories. An obligation rated BBB exhibits adequate protection parameters. However, adverse economic conditions or changing circumstances are more likely to weaken the obligor's capacity to meet its financial commitments on the obligation. 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, 2021, are as follows:

	Price range (Cdn$)		Trading volume
	High	Low	(000s)
2021			
January	24.82	21.12	149,769
February	27.42	21.07	266,808
March	29.55	25.36	313,417
April	27.45	24.81	109,858
May	29.31	26.39	185,597
June	31.38	28.45	182,259
July	30.47	24.25	132,185
August	24.90	21.90	188,953
September	27.22	22.86	225,919
October	32.99	26.29	159,751
November	34.35	30.70	251,190
December	32.20	28.77	231,028

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 2021 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, one of the world's largest integrated forest products companies, on July 1, 2016. From 2007 until February 2016, she also served as Weyerhaeuser's 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.
John D. Gass[1][4] Florida, U.S.	Director since 2014 Independent	John Gass is a former vice president of Chevron Corporation, a major integrated oil and gas company, and former president of 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 has a bachelor's degree in civil engineering from Vanderbilt University and a master's degree in civil engineering from Tulane University. He is a member of the American Society of Civil Engineers and the Society of Petroleum Engineers.

Russell Girling[2][3] Alberta, Canada	Director since 2021 Independent	Russell (Russ) K. Girling was the President and Chief Executive Officer of TransCanada Pipelines Limited and TC Energy Corporation, a North American energy infrastructure company, from 2010 until his retirement on December 31, 2020. Mr. Girling is chair and a director of the board of Nutrien Ltd. Until December 31, 2020, Mr. Girling was a member of the U.S. National Petroleum Council, the U.S. Business Roundtable, and served as a director of the American Petroleum Institute, the Business Council of Canada and the Business Council of Alberta. Mr. Girling is a graduate of the Institute of Corporate Directors Education Program and holds a Bachelor of Commerce and a Master of Business Administration (Finance) from the University of Calgary.
Jean Paul Gladu[1][2] Ontario, Canada	Director since 2020 Independent	Jean Paul (JP) Gladu previously served as president and chief executive officer of the Canadian Council for Aboriginal Business for approximately eight years. He has over 25 years of experience in the natural resource sector, including working with Indigenous communities and organizations, environmental non-governmental organizations, industry and governments across Canada. Mr. Gladu also serves on the boards of Noront Resources Ltd., Broden Mining Ltd. and the Institute of Corporate Directors. He was appointed chancellor of St. Paul's University College at the University of Waterloo in 2017 and served on the board of Ontario Power Generation. Mr. Gladu has a forestry technician diploma, an undergraduate degree in forestry from Northern Arizona University, an Executive MBA from Queen's University and the ICD.D from the Rotman School of Management at the University of Toronto. Anishinaabe from Thunder Bay, Mr. Gladu is a member of Bingwi Neyaashi Anishinaabek (an Ojibwa First Nation) located on Lake Nipigon, Ontario.

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, he 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. He serves on the board of directors of Argus Media Limited. Mr. Houston has a bachelor's degree in chemical engineering from the University of Illinois and an honorary doctorate of public administration degree from Massachusetts Maritime Academy. He has served on a variety of advisory councils, including an appointment by President George H.W. Bush to the National Infrastructure Advisory Council and serving on the Chemical Sciences Leadership Council at the University of Illinois and the Advisory Council at the Center for Energy, Marine Transportation & Public Policy at Columbia University. He also serves on the Alexander S. Onassis Public Benefit Foundation board, is honorary consul to the Texas Region for the Principality of Liechtenstein and is 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, his accountabilities have spanned operations in the Wood Buffalo region and offshore East Coast Canada and in the North Sea, to 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. He 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 serves as a member of the Board of Governors, Executive Committee and Oil Sands CEO Council of the Canadian Association of Petroleum Producers and is one of the CEOs leading Canada's Oil Sands Pathways to Net Zero. He has co-chaired the Canadian Council for Aboriginal Business' procurement initiative and is a past board member of Accenture Global Energy. Mr. Little has degrees in computer science from the University of Calgary and applied petroleum engineering technology from SAIT, is a graduate of the advanced management program at Harvard Business School and has an honorary degree in business administration from SAIT. He received the Canadian Engineering Leader Award from the Schulich School of Engineering at the University of Calgary.

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, Mr. MacDonald served as chief executive officer and president of Hertz Equipment Rental Corporation and as interim chief executive officer of Hertz Corporation. He 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 and held senior financial roles at Dell Inc. Prior to Dell, 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, Sunoco Logistics L.P. and CDK Global. Mr. MacDonald has a bachelor of science in chemistry from Mount Allison University and an MBA from McGill 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, the Nature Conservancy of Canada and the Royal Alexandra Hospital Foundation Social Enterprise Company. She has previously served on a number of boards, including as chair of the CBC Pension Plan board of trustees, the Edmonton International Airport and the Edmonton Chamber of Commerce. She has also served on the board of directors of the Canadian Broadcasting Corporation. Ms. McCaw has 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 Enlighten Innovations Inc., a private-equity backed fuel upgrading technology company. Prior to this, 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, in addition to her role as Executive Vice President of Heavy Oil Americas. Prior to joining Shell, she worked with Petro-Canada, Chevron and BHP Petroleum in the upstream business units in a combination of technical, exploration and development, and commercial roles. Ms. Mitchelmore has been a director of the Bank of Montreal since 2015, Cheniere Energy Inc. since July 2021 and AIMCo since January 2022, and has served on the boards of Shell Canada Limited, the Canada Advisory Board at Catalyst, Inc. and Trans Mountain Corporation. Ms. Mitchelmore has a bachelor of science degree (Honours) in geophysics from Memorial University of Newfoundland, a master of science degree in geophysics from the University of Melbourne, Australia, and a MBA with distinction from Kingston Business School in London, England.
Eira M. Thomas[1][4] British Columbia, Canada	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 chief executive officer of Stornoway Diamond Corp. Ms. Thomas graduated from the University of Toronto with a bachelor of science degree in geology. Her awards and recognition include being named one of Canada's Top 40 Under 40 by Caldwell Partners and *Report on Business* magazine, selected as one of Canada's top 100 most powerful women by WXN and being one of only four Canadians in 2008 to be named to the Forum of 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. (now Nutrien Ltd.), 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. He had previously served as Agrium's 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. He 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
Martha Hall Findlay	Alberta, Canada	Chief Climate Officer
Bruno Francoeur	Alberta, Canada	Chief Transformation Officer
Paul Gardner	Alberta, Canada	Chief People Officer
Mike MacSween	Alberta, Canada	Executive Vice President, Upstream
Shelley Powell	Alberta, Canada	Senior Vice President, E&P and In Situ
Kris Smith	Alberta, Canada	Executive Vice President, Downstream
Arlene Strom	Alberta, Canada	Chief Sustainability Officer and General Counsel

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, 2022, the directors and executive officers of Suncor as a group beneficially owned, or controlled or directed, directly or indirectly, 483,867 common shares of Suncor, which represents 0.03% of the outstanding common shares of Suncor. Inclusive of deferred share units, the total share ownership of Suncor's directors and executive officers as at February 21, 2022 is 1,550,068 common shares and units of Suncor (for the purpose of share ownership targets, deferred share units are included).

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. 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 that was initiated on July 1, 2019. Mr. Gass ceased to be a director of Weatherford on December 13, 2019; and (ii) Mr. Gladu who was an officer of A2A Rail, which obtained creditor protection under Canadian insolvency legislation that was initiated on June 18, 2021. Mr. Gladu ceased to be an officer of A2A Rail on June 2, 2021.; 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.

Conflicts of Interest

The directors and officers of Suncor may be directors or officers of entities that are in competition with or are customers or suppliers of Suncor or certain entities in which Suncor holds an equity investment. As such, these directors or officers may encounter conflicts of interest in the administration of their duties with respect to Suncor. Directors and officers of Suncor are required to disclose the existence of potential conflicts in accordance with Suncor's policies and in accordance with the CBCA.

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. Girling, 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, Mr. Girling 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 auditors, KPMG LLP (Calgary, Canada), in 2021 and 2020 are as follows:

($ thousands)	2021	2020
Audit fees	5,702	4,723
Audit-related Fees	465	457
Tax fees	—	—
All other fees	—	—
Total	6,167	5,180

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, 2021, 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, 2021, (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, 2021.

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, 2021, 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, Suncor's independent qualified reserves evaluator. 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.

The company's independent auditors are KPMG LLP, Chartered Professional Accountants, who have issued an independent auditor's report dated February 23, 2022, in respect of the company's Consolidated Financial Statements, which comprise the Consolidated Balance Sheets as at December 31, 2021, and December 31, 2020, and the Consolidated Statements of Comprehensive Income (Loss), Changes in Equity and Cash Flows for the years ended December 31, 2021, and December 31, 2020, and the related notes, and the report on internal control over financial reporting as at December 31, 2021, and December 31, 2020. KPMG has confirmed with respect to the company that they are independent within the meaning of the relevant rules and related interpretations prescribed by the relevant professional bodies in Canada and any applicable legislation or regulations and also that they are independent accountants with respect to the company under all relevant U.S. professional and regulatory standards.

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 2022 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 2021 audited Consolidated Financial Statements and in the MD&A.

Further information about Suncor, filed with Canadian securities commissions and the U.S. Securities and Exchange Commission (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 estimates; the current and potential adverse impacts of the COVID-19 pandemic, including the status of the pandemic and future waves; 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:

- *Suncor's expectation that a final sanctioning to potentially replace Suncor's Millennium and North Steepbank mines is not expected until later in the decade;*
- *Expectations about Terra Nova and the ALE Project, including the expectation that Terra Nova will have a safe and reliable return to operations before the end of 2022 and that the ALE Project will extend production life by approximately 10 years and provide an additional 70 million barrels of resource for the partnership and provide many benefits to the Newfoundland and Labrador and Canadian economies in the form of taxes, royalties and employment;*
- *Statements about Suncor's coke-fired boiler replacement program, including the expectation that it will provide reliable steam generation, reduce the GHG emissions intensity associated with steam production at Oil Sands Base operations by approximately 25%, reduce GHG emissions in the province of Alberta by approximately 5.1Mt per year, the expectation that the excess electricity produced will be transmitted to Alberta's power grid and the expected benefits therefrom, and cost approximately $1.4 billion with an expected in-service date between 2024 and 2025;*
- *The aim, objectives and potential benefits of Suncor's clean energy investments, including Enerkem Inc., LanzaJet Inc., Svante Inc. and the Varennes Carbon Recycling facility, and Suncor's belief that these investments complement Suncor's existing product mix and demonstrate Suncor's involvement in the evolving global energy expansion;*
- *Suncor's strategic objective to become a net-zero GHG emissions company by 2050 and to substantially contribute to society's net-zero ambitions as well as Suncor's goal of targeting*

annual emissions reductions of 10 megatonnes across its value chain by 2030 and the plans Suncor has to achieve these objectives and goals;

- *Statements regarding the Oil Sands Pathways to Net Zero alliance, including the goals, expectations regarding timing and the expected pathways the alliance will take to address GHG emissions;*
- *Suncor's expectation that the Northern Courier Pipeline will provide the eight Indigenous communities (which Suncor has partnered with) reliable income for decades;*
- *Expectations about the Meadow Creek East Project, including the expectation that, if it is completed, the project will be developed in two stages with an anticipated gross production capacity up to 80 mbbls/d and about the Meadow Creek West Project, including the expectation that the project will be developed in a single stage with an anticipated gross production capacity of 40 mbbls/d;*
- *Expectations about the West White Rose Project, including the expectation that it would extend the life of the existing White Rose assets and the company's estimated share of peak oil production of 20 mbbls/d;*
- *The company's expectation that it will operate the Fort Hills asset at average utilization rates of 90% throughout 2022;*
- *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 2022;*
- *Statements about Buzzard Phase 2, which is expected to extend production life of the existing Buzzard field, and that Buzzard Phase 2 is expected to reach its peak production in 2022, adding approximately 12,000 boe/d gross (approximately 3,500 boe/d net to Suncor) to existing Buzzard production;*
- *Expectations about the Lewis Project, including that the project is expected to be developed in stages, with anticipated peak production of 160 mbbls/d;*
- *The expectation that the Syncrude joint venture owners' 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 if economic conditions provide suitable, the expectation that the MLX-W program will sustain bitumen production levels at the Mildred Lake site after resource depletion at the North Mine and use existing mining and extraction facilities, and the expectation that MLX-W will achieve first oil in 2025;*
- *Expectations about the Fenja development project, including the plan for development, first oil anticipated in 2023 and the expectation that peak production will reach 29 mboe/d (5.1 mboe/d, net to Suncor) in 2024;*
- *The estimated cost of Suncor's remaining exploration work program commitment in Libya at December 31, 2021, of US$359 million;*
- *The expectation that the drilling of new well pairs and infill wells at Firebag and MacKay River will assist in maintaining production levels in future years;*

- *Potential future wind and solar power projects, including the expectations regarding the capacity and construction of the Forty Mile Wind Power Project, including the estimated total capital spend of $300 million and its planned completion in late 2022;*
- *Suncor's belief that debottlenecking capacity and timing at Firebag will depend on economic conditions and can be supported by integrated well pad development and solvent SAGD technologies;*
- *The potential for future in situ production to be supported at Meadow Creek, Lewis, OSLO, Gregoire, Chard and Kirby; and*
- *The expectation that turnaround maintenance will improve reliability and operational efficiency.*

Also:

- *Expectations (including with respect to timing), goals and plans around technologies, including autonomous haulage systems, permanent aquatic storage structures, expanding solvent SAGD, Solvent+, non-aqueous extraction, partial upgrading and heavy oil late life energy recovery;*
- *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 2022, including those identified under the Future Development Costs table in the Statement of Reserves Data and Other Oil and Gas Information section of this AIF; Suncor's belief that internally generated cash flows, existing and future credit facilities, issuing commercial paper and, if needed, 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;*
- *Nameplate capacities;*
- *The timing and impact of Suncor's planned workforce reductions and downstream reorganization;*
- *Expectations about royalties and income taxes and their impact on Suncor;*
- *Expectations regarding tailings management plans and regulatory processes with respect thereto;*
- *Expectations regarding Suncor's share repurchase program and the NCIB;*
- *Expectations concerning the timing of negotiations for collective agreements;*
- *Anticipated effects of and responses to environmental laws and regulations, including climate change and GHG emissions laws and regulations, 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 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 (including as a result of demand and supply effects resulting from the COVID-19 pandemic and the actions of OPEC+); 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 and future production estimates; Suncor's ability to access capital markets at acceptable rates or to issue 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 23, 2022, 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, 2021, and dated February 23, 2022 which is available on SEDAR at www.sedar.com.

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.

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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, 2021. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2021, 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, 2021, 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 Ltd.	December 31, 2021	Oil Sands In Situ, Canada	—	27,159	—	27,159
GLJ Ltd.	December 31, 2021	Oil Sands Mining, Canada	—	27,154	—	27,154
GLJ Ltd.	December 31, 2021	East Coast Canada, Newfoundland Offshore, Canada	—	6,284	—	6,284
GLJ Ltd.	December 31, 2021	Offshore, United Kingdom	—	2,031	—	2,031
GLJ Ltd.	December 31, 2021	Offshore, Norway	—	585	—	585
			—	63,212	—	63,212

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 Ltd., Calgary, Alberta, Canada, February 23, 2022

"Tim R. Freeborn"

Tim R. Freeborn, P.Eng.
Vice President and Chief Financial Officer

SCHEDULE "D" – 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 23, 2022

[GRAPHIC]

Suncor Energy Inc.

150 - 6 Avenue S.W., Calgary, Alberta, Canada T2P 3E3

T: 403-296-8000

[GRAPHIC] Suncor.com

Exhibit 99.2

AUDITED CONSOLIDATED FINANCIAL STATEMENTS AND NOTES - TABLE OF CONTENTS

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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 International Financial Reporting Standards as issued by the International Accounting Standards Board. 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 23, 2022

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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, 2021, 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, 2021. 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, 2021, 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 23, 2022

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 sheets of Suncor Energy Inc. (the Company) as of December 31, 2021 and 2020, the related consolidated statements of comprehensive income (loss), changes in equity, and cash flows for each of the years in the two-year period ended December 31, 2021, 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, 2021, 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, 2021 and 2020, and its financial performance and its cash flows for each of the years in the two-year period ended December 31, 2021, 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, 2021 based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

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.

Indicators of impairment loss or reversal related to Oil Sands and Exploration and Production property, plant and equipment

As discussed in Note 3(m) 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. Quarterly, 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 independent qualified reserves evaluators. The Company engages independent qualified reserves evaluators to evaluate the Company's proved and probable oil reserves. The carrying amount of the Company's Oil Sands and Exploration and Production property, plant and equipment balance as of December 31, 2021 was $55,374 million.

We identified the evaluation of the assessment of indicators of impairment loss or reversal related to 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 following are the primary procedures we performed to address this critical audit matter. We evaluated the design and tested the operating effectiveness of certain internal controls related to the critical audit matter. This included controls related to 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 externally evaluated proved and probable oil 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 qualified reserves evaluators engaged by the Company, who evaluated the proved and probable oil reserves. We evaluated the methodology used by the independent qualified reserves evaluators to evaluate proved and probable oil reserves for compliance with regulatory standards.

Impairment of the Fort Hills cash generating unit

As discussed in note 16 to the consolidated financial statements, the Company identified an indicator of impairment at December 31, 2021 for the Fort Hills cash generating unit ("CGU") and performed an impairment test to determine the recoverable amount of the CGU based on the fair value less cost of disposal. The estimated recoverable amount of the CGU involves numerous assumptions, including forecasted production volumes, commodity prices (including foreign exchange rates), operating costs ("forecasted cash flow assumptions"), and discount rate.

We identified the assessment of the impairment of the Fort Hills CGU 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 could have had a significant effect on the Company's calculation of the recoverable amount of the CGU. 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. Additionally, the evaluation of the impairment of the Fort Hills CGU required involvement of valuation professionals with specialized skills and knowledge.

The following are the primary procedures we performed to address this critical audit matter. We evaluated the design and tested the operating effectiveness of certain internal controls related to the critical audit matter. This included controls related to the Company's determination of the recoverable amount of the CGU, including controls related to the determination of the forecasted cash flow assumptions and discount rate. We performed sensitivity analyses over the discount rate and forecasted commodity price assumptions to assess the impact of those assumptions on the Company's determination of the recoverable amount of the CGU. We evaluated the Company's future commodity price (including foreign exchange rate) estimates by comparing to a number of publicly available external price curves for the same benchmark pricing. We evaluated the forecasted production volumes and operating cost 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 and comparable CGUs. We compared the Company's current year actual production volumes and operating costs to those respective 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 qualified reserves evaluators engaged by the Company, who evaluated the proved and probable oil reserves. We evaluated the methodology used by independent qualified reserves evaluators to evaluate proved and probable oil reserves for compliance with regulatory standards. We involved valuation professionals with specialized skills and knowledge, who assisted in:

- evaluating the Company's CGU discount rate, by comparing the inputs against publicly available market data for comparable entities and assessing the resulting discount rate
- evaluating the Company's estimate of recoverable amount of the CGU by comparing to publicly available market data and valuation metrics for comparable entities.



Chartered Professional Accountants

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

Calgary, Canada
February 23, 2022

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CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

For the years ended December 31 ($ millions)	Notes	2021	2020
Revenues and Other Income			
Operating revenues, net of royalties	6	**39 132**	24 662
Other income	7	**(31)**	390
		39 101	25 052
Expenses			
Purchases of crude oil and products		**13 791**	9 112
Operating, selling and general [1]	8 and 26	**11 366**	9 794
Transportation and distribution [1]		**1 479**	1 551
Depreciation, depletion, amortization and impairment	15 and 16	**5 850**	9 526
Exploration		**47**	186
Gain on disposal of assets	33	**(257)**	(16)
Financing expenses	9	**1 255**	996
		33 531	31 149
Earnings (Loss) before Income Taxes		**5 570**	(6 097)
Income Tax Expense (Recovery)			
Current	10	**1 395**	(659)
Deferred	10 and 16	**56**	(1 119)
		1 451	(1 778)
Net Earnings (Loss)		**4 119**	(4 319)
Other Comprehensive Income (Loss)			
Items That May be Subsequently Reclassified to Earnings:			
Foreign currency translation adjustment		**(63)**	(22)
Items That Will Not be Reclassified to Earnings:			
Actuarial gain (loss) on employee retirement benefit plans, net of income taxes		**856**	(196)
Other Comprehensive Income (Loss)		**793**	(218)
Total Comprehensive Income (Loss)		**4 912**	(4 537)
Per Common Share (dollars)	11		
Net earnings (loss) – basic and diluted		**2.77**	(2.83)
Cash dividends		**1.05**	1.10

(1) Prior period amounts have been reclassified to align with the current year presentation of transportation and distribution expense. For the year ended December 31, 2020, $133 million was reclassified from operating, selling and general expense to transportation and distribution expense. This reclassification had no effect on net earnings (loss).

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

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CONSOLIDATED BALANCE SHEETS

($ millions)	Notes	December 31 2021	December 31 2020
Assets			
Current assets			
Cash and cash equivalents	12	**2 205**	1 885
Accounts receivable		**4 534**	3 157
Inventories	14	**4 110**	3 617
Income taxes receivable		**128**	727
Total current assets		**10 977**	9 386
Property, plant and equipment, net	15 - 17 and 33	**65 546**	68 130
Exploration and evaluation	18	**2 226**	2 286
Other assets	19	**1 307**	1 277
Goodwill and other intangible assets	20	**3 523**	3 328
Deferred income taxes	10	**160**	209
Total assets		**83 739**	84 616
Liabilities and Shareholders' Equity			
Current liabilities			
Short-term debt	21	**1 284**	3 566
Current portion of long-term debt	21	**231**	1 413
Current portion of long-term lease liabilities	21	**310**	272
Accounts payable and accrued liabilities		**6 503**	4 684
Current portion of provisions	24	**779**	527
Income taxes payable		**1 292**	87
Total current liabilities		**10 399**	10 549
Long-term debt	21	**13 989**	13 812
Long-term lease liabilities	21	**2 540**	2 636
Other long-term liabilities	22	**2 180**	2 840
Provisions	24	**8 776**	10 055
Deferred income taxes	10 and 16	**9 241**	8 967
Equity		**36 614**	35 757
Total liabilities and shareholders' equity		**83 739**	84 616

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 23, 2022

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CONSOLIDATED STATEMENTS OF CASH FLOWS

For the years ended December 31 ($ millions)	Notes	2021	2020
Operating Activities			
Net earnings (loss)		**4 119**	(4 319)
Adjustments for:			
Depreciation, depletion, amortization and impairment		**5 850**	9 526
Deferred income tax expense (recovery)	10 and 16	**56**	(1 119)
Accretion	9	**304**	278
Unrealized foreign exchange gain on U.S. dollar denominated debt	9	**(113)**	(312)
Change in fair value of financial instruments and trading inventory		**(13)**	108
Gain on disposal of assets	33	**(257)**	(16)
Loss on extinguishment of long-term debt	9 and 21	**80**	-
Share-based compensation		**205**	(238)
Exploration		**-**	80
Settlement of decommissioning and restoration liabilities		**(263)**	(231)
Other		**289**	119
Decrease (increase) in non-cash working capital	13	**1 507**	(1 201)
Cash flow provided by operating activities		**11 764**	2 675
Investing Activities			
Capital and exploration expenditures		**(4 555)**	(3 926)
Proceeds from disposal of assets	33	**335**	72
Other investments and acquisitions		**(28)**	(113)
Decrease (increase) in non-cash working capital	13	**271**	(557)
Cash flow used in investing activities		**(3 977)**	(4 524)
Financing Activities			
Net (decrease) increase in short-term debt		**(2 256)**	1 445
Repayment of long-term debt	21	**(2 451)**	-
Issuance of long-term debt		**1 423**	2 634
Lease liability payments		**(325)**	(335)
Issuance of common shares under share option plans		**8**	29
Repurchase of common shares	25	**(2 304)**	(307)
Distributions relating to non-controlling interest		**(9)**	(10)
Dividends paid on common shares		**(1 550)**	(1 670)
Cash flow (used in) provided by financing activities		**(7 464)**	1 786
Increase (Decrease) in Cash and Cash Equivalents		**323**	(63)
Effect of foreign exchange on cash and cash equivalents		**(3)**	(12)
Cash and cash equivalents at beginning of year		**1 885**	1 960
Cash and Cash Equivalents at End of Year		**2 205**	1 885
Supplementary Cash Flow Information			
Interest paid		**980**	1 028
Income taxes (received) paid		**(532)**	695

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

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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, 2019		25 167	566	899	15 410	42 042	1 531 874
Net loss		-	-	-	(4 319)	(4 319)	-
Foreign currency translation adjustment		-	-	(22)	-	(22)	-
Actuarial loss on employee retirement benefit plans, net of income taxes of $62	23	-	-	-	(196)	(196)	-
Total comprehensive (loss) income		-	-	(22)	(4 515)	(4 537)	-
Issued under share option plans		36	(7)	-	-	29	804
Repurchase of common shares for cancellation	25	(124)	-	-	(183)	(307)	(7 527)
Change in liability for share purchase commitment	25	65	-	-	103	168	-
Share-based compensation	26	-	32	-	-	32	-
Dividends paid on common shares		-	-	-	(1 670)	(1 670)	-
At December 31, 2020		25 144	591	877	9 145	35 757	1 525 151
Net earnings		**-**	**-**	**-**	**4 119**	**4 119**	**-**
Foreign currency translation adjustment		**-**	**-**	**(63)**	**-**	**(63)**	**-**
Actuarial gain on employee retirement benefit plans, net of income taxes of $277	23	**-**	**-**	**-**	**856**	**856**	**-**
Total comprehensive (loss) income		**-**	**-**	**(63)**	**4 975**	**4 912**	**-**
Issued under share option plans		**8**	**-**	**-**	**-**	**8**	**245**
Common shares forfeited		**-**	**-**	**-**	**-**	**-**	**(186)**
Repurchase of common shares for cancellation	25	**(1 382)**	**-**	**-**	**(922)**	**(2 304)**	**(83 959)**
Change in liability for share purchase commitment	25	**(120)**	**-**	**-**	**(110)**	**(230)**	**-**
Share-based compensation	26	**-**	**21**	**-**	**-**	**21**	**-**
Dividends paid on common shares		**-**	**-**	**-**	**(1 550)**	**(1 550)**	**-**
At December 31, 2021		**23 650**	**612**	**814**	**11 538**	**36 614**	**1 441 251**

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's operations include oil sands development, production and upgrading; offshore oil and gas; petroleum refining in Canada and the U.S.; and the company's Petro-Canada retail and wholesale distribution networks (including Canada's Electric Highway™, a coast-to-coast network of fast-charging electric vehicle stations). Suncor is developing petroleum resources while advancing the transition to a low-emissions future through investment in power, renewable fuels and hydrogen. Suncor also conducts energy trading activities focused principally on the marketing and trading of crude oil, natural gas, byproducts, refined products and power. Suncor has been recognized for its performance and transparent reporting on the Dow Jones Sustainability index, FTSE4Good and CDP. Suncor is also listed on the UN Global Compact 100 stock index. Suncor's common shares (symbol: SU) are listed on the Toronto Stock Exchange (TSX) and New York Stock Exchange (NYSE).

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).

During 2021, the company revised the presentation of certain expenses from "transportation" to "transportation and distribution" and reclassified certain operating, selling and general expenses to transportation and distribution to better reflect the nature of these expenses. There is no impact on net earnings (loss) and comparative periods have been restated to reflect this change.

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 23, 2022.

(b) Basis of Measurement

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

(c) Functional Currency and Presentation Currency

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

(d) Use of Estimates, Assumptions and Judgments

The timely preparation of financial statements requires that management make estimates and assumptions and use 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) Investments in Associates

Associates are entities for which the company has significant influence, but not control or joint control over the financial and operational decisions. Investments in associates are accounted for using the equity method of accounting and are initially recognized at cost and adjusted thereafter for the change in the company's share of the investee's profit or loss and Other Comprehensive Income (OCI) less distributions received until the date that significant influence ceases.

(d) 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 OCI.

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.

(e) 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 does not 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 partners.

(f) 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.

(g) 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 to sell and any changes in fair value are recognized in Other Income within the respective reporting segment to which the trading activity relates.

(h) 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.

(i) 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.

(j) 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.

(k) 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 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.

(l) 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, brand value and certain software costs.

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 10 years. Software costs are amortized over their expected useful lives, which range from five to six years. Expected useful lives of other intangible assets are reviewed on an annual basis.

(m) 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 since the last impairment loss was recognized. 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 the expected credit losses associated with its financial assets measured at amortized cost. Expected credit losses are measured as the difference between the cash flows that are due to the company and the cash flows that the company expects to receive, discounted at the effective interest rate determined at initial recognition. For trade accounts receivables, the company applies the simplified approach permitted by IFRS 9 *Financial Instruments*, which requires lifetime expected credit losses to be recognized from initial recognition of the receivables. To measure expected credit losses, accounts receivables are grouped based on the number of days the receivables have been outstanding and the internal credit assessments of the customers. Credit risk for longer term receivables is assessed based on an external credit rating of the counterparty. For longer term receivables with credit risk that has not increased significantly since the date of recognition, the company measures the expected credit loss as the twelve-month expected credit loss. Expected credit losses are recognized in net earnings.

(n) 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.

(o) 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.

(p) 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.

(q) 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.

(r) 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 and certain investments 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.

(s) 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, 2021 or 2020.

(t) 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.

(u) Dividend Distributions

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

(v) 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.

(w) Emissions Obligations

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

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.

(x) Leases

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 on 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. Judgment is applied to determine the lease term where a renewal option exists. Right-of-use assets are depreciated 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 reduced by impairment losses or adjusted for certain remeasurements of the lease liability.

The company has 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. The lease payments are recognized as an expense when incurred over the lease term. As well, the company has accounted for each lease component and any non-lease components as a single lease component for crude oil storage tanks.

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.

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.

(y) Government Grants

Government grants are recognized when the company has reasonable assurance that it has complied with the relevant conditions of the grant and that it will be received. The company recognizes the grants that compensate the company for expenses incurred against the financial statement line item that it is intended to compensate, or to other income if the grant is recognized in a different period than the underlying transaction.

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.

COVID-19

On January 30, 2020, the World Health Organization declared the COVID-19 outbreak a Public Health Emergency of International Concern and, on March 10, 2020, declared it to be a pandemic. Actions taken around the world to help mitigate the spread of COVID-19 include restrictions on travel, quarantines in certain areas, and forced closures for certain types of public places and businesses. These measures have and may continue to have significant disruption to business operations and a significant increase in economic uncertainty, with fluctuating demand for commodities leading to volatile prices and currency exchange rates, and a decline in long-term interest rates. Our operations and business are particularly sensitive to a reduction in the demand for, and prices of, commodities that are closely linked to Suncor's financial performance, including crude oil, refined petroleum products (such as jet fuel and gasoline), natural gas and electricity. The potential direct and indirect impacts of the economic volatility have been considered in management's estimates, and assumptions at period-end have been reflected in our results with any significant changes described in the relevant financial statement note.

The COVID-19 pandemic is an evolving situation that is expected to continue to have widespread implications for our business environment, operations and financial condition. Management cannot reasonably estimate the length or severity of this pandemic, or the extent to which the disruption may materially impact our consolidated statements of comprehensive income (loss), consolidated balance sheets and consolidated statements of cash flows.

Climate Change

Climate change and the transition to a lower-carbon economy from carbon-based sources to alternative energy were considered in preparing the consolidated financial statements. These may have significant impacts on the currently reported amounts of the company's assets and liabilities discussed below and on similar assets and liabilities that may be recognized in the future.

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, 2021, 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, 2021, which could differ significantly from other points in time throughout the year, or future periods. Changes in market and regulatory conditions and assumptions, as well as climate change, and the evolving worldwide demand for energy and global advancement of alternative sources of energy that are not sourced from fossil fuels can materially impact the estimation of net reserves. The timing in which global energy markets transition from carbon-based sources to alternative energy is highly uncertain.

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, income taxes, 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. In addition, climate change, and the evolving worldwide demand for energy and global advancement of alternative sources of energy that are not sourced from fossil fuels could result in a change in assumptions used in determining the recoverable amount and could affect the carrying value and useful life of the related assets. The timing in which global energy markets transition from carbon-based sources to alternative energy is highly uncertain.

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. In addition, climate change, and the evolving worldwide demand for energy and global advancement of alternative sources of energy that are not sourced from fossil fuels could result in a change in assumptions used in determining the carrying value of the liabilities. The timing in which global energy markets transition from carbon-based sources to alternative energy is highly uncertain.

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 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.

5. NEW IFRS STANDARDS

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.

Deferred Tax Related to Assets and Liabilities Arising from a Single Transaction

In May 2021, the IASB issued *Deferred Tax related to Assets and Liabilities arising from a Single Transaction (Amendments to IAS 12)*. The amendments narrowed the scope of the initial recognition exemption to exclude transactions that give rise to equal and offsetting temporary differences. The amendments are effective January 1, 2023, with early adoption permitted. The company does not anticipate any significant impact from these amendments on the consolidated financial statements as a result of the initial application.

Definition of Accounting Estimates

In February 2021, the IASB issued *Definition of Accounting Estimates (Amendments to IAS 8).* The amendments introduced a definition of accounting estimates and included other amendments to help entities distinguish changes in accounting estimates from changes in accounting policies. The amendments are effective January 1, 2023, with early adoption permitted. The company does not anticipate any significant impact from these amendments on the consolidated financial statements as a result of the initial application.

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, and the company's joint interest in the Fort Hills partnership 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 (the latter of which the company sold during 2021 – see note 33) in the United Kingdom (U.K.), exploration and production of crude oil and gas at Oda, and the development of the Fenja field in Norway, as well as the marketing and risk management of crude oil and natural gas.

- 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, the development of the Forty Mile Wind Project in Alberta, as well as other investments in waste-to-biofuels, chemicals, and carbon capture projects.

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

For the years ended December 31 ($ millions)	Oil Sands		Exploration and Production		Refining and Marketing		Corporate and Eliminations		Total	
	2021	2020	**2021**	2020	**2021**	2020	**2021**	2020	**2021**	2020
Revenues and Other Income										
Gross revenues	**15 319**	7 792	**2 978**	1 899	**22 808**	15 180	**28**	29	**41 133**	24 900
Intersegment revenues	**4 601**	2 825	**-**	-	**107**	92	**(4 708)**	(2 917)	**-**	-
Less: Royalties	**(1 523)**	(95)	**(478)**	(143)	**-**	-	**-**	-	**(2 001)**	(238)
Operating revenues, net of royalties	**18 397**	10 522	**2 500**	1 756	**22 915**	15 272	**(4 680)**	(2 888)	**39 132**	24 662
Other income (loss)	**6**	298	**17**	54	**(50)**	48	**(4)**	(10)	**(31)**	390
	18 403	10 820	**2 517**	1 810	**22 865**	15 320	**(4 684)**	(2 898)	**39 101**	25 052
Expenses										
Purchases of crude oil and products	**1 444**	844	**-**	-	**16 807**	11 243	**(4 460)**	(2 975)	**13 791**	9 112
Operating, selling and general [1]	**8 056**	7 169	**429**	476	**2 019**	1 759	**862**	390	**11 366**	9 794
Transportation and distribution [1]	**1 126**	1 223	**112**	100	**282**	271	**(41)**	(43)	**1 479**	1 551
Depreciation, depletion, amortization and impairment	**4 585**	6 430	**324**	2 147	**853**	867	**88**	82	**5 850**	9 526
Exploration	**12**	57	**35**	129	**-**	-	**-**	-	**47**	186
(Gain) loss on disposal of assets	**(4)**	(1)	**(227)**	-	**(19)**	(24)	**(7)**	9	**(257)**	(16)
Financing expenses	**359**	336	**53**	47	**56**	37	**787**	576	**1 255**	996
	15 578	16 058	**726**	2 899	**19 998**	14 153	**(2 771)**	(1 961)	**33 531**	31 149
Earnings (Loss) before Income Taxes	**2 825**	(5 238)	**1 791**	(1 089)	**2 867**	1 167	**(1 913)**	(937)	**5 570**	(6 097)
Income Tax Expense (Recovery)										
Current	**729**	(645)	**473**	64	**576**	325	**(383)**	(403)	**1 395**	(659)
Deferred	**(51)**	(797)	**33**	(321)	**113**	(24)	**(39)**	23	**56**	(1 119)
	678	(1 442)	**506**	(257)	**689**	301	**(422)**	(380)	**1 451**	(1 778)
Net Earnings (Loss)	**2 147**	(3 796)	**1 285**	(832)	**2 178**	866	**(1 491)**	(557)	**4 119**	(4 319)
Capital and Exploration Expenditures	**3 168**	2 736	**270**	489	**825**	515	**292**	186	**4 555**	3 926

(1) Prior period amounts of the Refining and Marketing segment have been reclassified to align with the current year presentation of transportation and distribution expense. For the year ended December 31, 2020, $133 million was reclassified from operating, selling and general expense to transportation and distribution expense. This reclassification had no effect on net earnings (loss).

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 ($ millions)	2021 North America	2021 International	2021 Total	2020 North America	2020 International	2020 Total
Oil Sands						
SCO and diesel	**14 452**	**-**	**14 452**	8 574	-	8 574
Bitumen	**5 468**	**-**	**5 468**	2 043	-	2 043
	19 920	**-**	**19 920**	10 617	-	10 617
Exploration and Production						
Crude oil and natural gas liquids	**1 709**	**1 257**	**2 966**	1 089	806	1 895
Natural gas	**-**	**12**	**12**	-	4	4
	1 709	**1 269**	**2 978**	1 089	810	1 899
Refining and Marketing						
Gasoline	**9 983**	**-**	**9 983**	6 585	-	6 585
Distillate	**9 832**	**-**	**9 832**	6 525	-	6 525
Other	**3 100**	**-**	**3 100**	2 162	-	2 162
	22 915	**-**	**22 915**	15 272	-	15 272
Corporate and Eliminations						
	(4 680)	**-**	**(4 680)**	(2 888)	-	(2 888)
Total Gross Revenue from Contracts with Customers	**39 864**	**1 269**	**41 133**	24 090	810	24 900

Geographical Information

Operating Revenues, net of Royalties

($ millions)	2021	2020
Canada	**32 286**	20 588
United States	**5 818**	3 312
Other foreign	**1 028**	762
	39 132	24 662

Non-Current Assets(1)

($ millions)	December 31 2021	December 31 2020
Canada	**68 900**	71 040
United States	**2 020**	1 856
Other foreign	**1 682**	2 125
	72 602	75 021

(1) Excludes deferred income tax assets.

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7. OTHER INCOME

Other income consists of the following:

($ millions)	2021	2020
Energy trading activities		
Gains recognized in earnings	**43**	126
Losses on inventory valuation	**(10)**	(25)
Short-term commodity risk management	**(198)**	49
Investment and interest income	**64**	94
Insurance proceeds[1]	**69**	96
Other	**1**	50
	(31)	390

(1) 2021 includes insurance proceeds for the outages at Mackay River and the secondary extraction facilities at Oil Sands Base Plant and 2020 includes insurance proceeds for MacKay River, both within the Oil Sands segment.

8. OPERATING, SELLING AND GENERAL EXPENSE

Operating, Selling and General expense consists of the following:

($ millions)	2021	2020
Contract services[1]	**4 090**	4 165
Employee costs[1]	**3 884**	2 813
Materials	**880**	951
Energy	**1 500**	1 113
Equipment rentals and leases	**418**	361
Travel, marketing and other[2]	**594**	391
	11 366	9 794

(1) The company incurred $8.6 billion of contract services and employee costs for the year ended December 31, 2021 (2020 – $7.5 billion), of which $8.0 billion (2020 – $7.0 billion) was recorded in Operating, Selling and General expense and $0.6 billion was recorded as Property, Plant and Equipment (2020 – $0.5 billion). Employee costs include salaries, benefits and share-based compensation.

(2) Prior period amounts have been reclassified to align with the current year presentation of transportation and distribution expense. For the year ended December 31, 2020, $133 million was reclassified from operating, selling and general expense to transportation and distribution expense. This reclassification had no effect on net earnings (loss).

9. FINANCING EXPENSES

Financing expenses consist of the following:

($ millions)	2021	2020
Interest on debt	**834**	884
Interest on lease liabilities	**161**	166
Capitalized interest at 5.0% (2020 –4.8%)	**(144)**	(120)
Interest expense	**851**	930
Interest on partnership liability	**51**	52
Interest on pension and other post-retirement benefits	**59**	54
Accretion	**304**	278
Foreign exchange gain on U.S. dollar denominated debt	**(113)**	(312)
Operational foreign exchange and other	**23**	(6)
Loss on extinguishment of long-term debt	**80**	-
	1 255	996

10. INCOME TAXES

Income Tax Expense (Recovery)

($ millions)	2021	2020
Current:		
Current year	**1 353**	(650)
Adjustments in respect of current income tax of prior years	**42**	(9)
Deferred:		
Origination and reversal of temporary differences	**29**	(973)
Adjustments in respect of deferred income tax of prior years	**23**	(52)
Changes in tax rates and legislation	**8**	(106)
Movement in unrecognized deferred income tax assets	**(4)**	12
Total income tax expense (recovery)	**1 451**	(1 778)

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)	2021	2020
Earnings (loss) before income tax	**5 570**	(6 097)
Canadian statutory tax rate	**24.24%**	24.96%
Statutory tax	**1 350**	(1 522)
Add (deduct) the tax effect of:		
Non-taxable component of capital gains	**(12)**	(45)
Share-based compensation and other permanent items	**3**	7
Assessments and adjustments	**65**	(58)
Impact of income tax rates and legislative changes	**8**	(173)
Non-taxable component of dispositions	**(66)**	-
Foreign tax rate differential	**111**	3
Movement in unrecognized deferred income tax assets	**(4)**	12
Other	**(4)**	(2)
Total income tax expense (recovery)	**1 451**	(1 778)
Effective tax rate	**26.1%**	29.2%

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 Expense (Recovery)		Deferred Income Tax Liability (Asset)	
($ millions)	2021	2020	December 31 2021	December 31 2020
Property, plant and equipment	**(260)**	(1 084)	**11 477**	11 963
Decommissioning and restoration provision	**141**	21	**(1 936)**	(2 304)
Employee retirement benefit plans	**(142)**	34	**(470)**	(605)
Tax loss carry-forwards	**161**	(20)	**(15)**	(176)
Other	**156**	(70)	**25**	(120)
Net deferred income tax expense (recovery) and liability	**56**	(1 119)	**9 081**	8 758

Change in Deferred Income Tax Balances

($ millions)	2021	2020
Net deferred income tax liability, beginning of year	**8 758**	9 967
Recognized in deferred income tax expense (recovery)	**56**	(1 119)
Recognized in other comprehensive income	**277**	(62)
Foreign exchange, acquisition and other	**(10)**	(28)
Net deferred income tax liability, end of year	**9 081**	8 758

Deferred Tax in Shareholders' Equity

($ millions)	2021	2020
Deferred Tax in Other Comprehensive Income		
Actuarial gain (loss) on employment retirement benefit plans	**277**	(62)
Total income tax expense (recovery) reported in equity	**277**	(62)

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 a $74 million (2020 – $78 million) deferred income tax asset on $606 million (2020 – $640 million) of capital losses related to unrealized 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, 2021, on unremitted net earnings of foreign subsidiaries, as the company is able to control the timing and amount of distributions and is not expected to incur any taxes associated with future distributions.

11. EARNINGS (LOSS) PER COMMON SHARE

($ millions)	2021	2020
Net earnings (loss)	**4 119**	(4 319)
(millions of common shares)		
Weighted average number of common shares	**1 488**	1 526
Dilutive securities:		
Effect of share options	**1**	-
Weighted average number of diluted common shares	**1 489**	1 526
(dollars per common share)		
Basic and diluted earnings (loss) per share	**2.77**	(2.83)

12. CASH AND CASH EQUIVALENTS

($ millions)	December 31 2021	December 31 2020
Cash	**1 971**	1 523
Cash equivalents	**234**	362
	2 205	1 885

13. SUPPLEMENTAL CASH FLOW INFORMATION

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

($ millions)	2021	2020
Accounts receivable	**(1 324)**	954
Inventories	**(551)**	121
Accounts payable and accrued liabilities[1]	**1 588**	(1 605)
Current portion of provisions[1]	**235**	122
Income taxes payable (net)[2]	**1 830**	(1 350)
	1 778	(1 758)
Relating to:		
Operating activities	**1 507**	(1 201)
Investing activities	**271**	(557)
	1 778	(1 758)

(1) Prior period amounts of the current portion of provisions have been reclassified to conform to the current year presentation. For the year ended December 31, 2020, $133 million was reclassified from accounts payable and accrued liabilities to current portion of provisions. This reclassification had no effect on the non-cash working capital.

(2) During the twelve months ended December 31, 2021, the increase in taxes payable was primarily related to the company's 2021 current income tax expense, which is payable in early 2022.

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, 2019	2 155	310	2 621	-	12 884	455	-
Changes from financing cash flows:							
Net issuance of commercial paper	1 445	-	-	-	-	-	-
Gross proceeds from issuance of long-term debt	-	-	-	-	2 651	-	-
Debt issuance costs	-	-	-	-	(17)	-	-
Dividends paid on common shares	-	-	-	-	-	-	(1 670)
Lease liability payments	-	(335)	-	-	-	-	-
Distributions to non-controlling interest	-	-	-	-	-	(10)	-
Non-cash changes:							
Dividends declared on common shares	-	-	-	-	-	-	1 670
Unrealized foreign exchange gains	(34)	-	-	(20)	(258)	-	-
Reclassification of debt	-	-	-	1 433	(1 433)	-	-
Reclassification of lease obligations	-	297	(297)	-	-	-	-
Deferred financing costs	-	-	-	-	(15)	-	-
Reassessment of partnership liability	-	-	-	-	-	(9)	-
New leases	-	-	312	-	-	-	-
At December 31, 2020	3 566	272	2 636	1 413	13 812	436	-
Changes from financing cash flows:							
Reduction of commercial paper	**(2 256)**	**-**	**-**	**-**	**-**	**-**	**-**
Gross proceeds from issuance of long-term debt	**-**	**-**	**-**	**-**	**1 446**	**-**	**-**
Debt issuance costs	**-**	**-**	**-**	**-**	**(23)**	**-**	**-**
Repayment of long-term debt	**-**	**-**	**-**	**(2 451)**	**-**	**-**	**-**
Loss on extinguishment of long-term debt	**-**	**-**	**-**	**80**	**-**	**-**	**-**
Realized foreign exchange (gains) and losses	**(79)**	**-**	**-**	**128**	**-**	**-**	**-**
Dividends paid on common shares	**-**	**-**	**-**	**-**	**-**	**-**	**1 550**

Lease liability payments	-	(325)	-	-	-	-	-
Distributions to non-controlling interest	-	-	-	-	-	(9)	-
Other	-	-	-	25	-	-	-
Non-cash changes:							
Dividends declared on common shares	-	-	-	-	-	-	(1 550)
Unrealized foreign exchange losses and (gains)	53	-	-	(47)	(168)	-	-
Reclassification of debt	-	-	-	1 083	(1 083)	-	-
Lease derecognition	-	-	(41)	-	-	-	-
Reclassification of lease obligations	-	363	(363)	-	-	-	-
Deferred financing costs	-	-	-	-	5	-	-
New lease liabilities	-	-	308	-	-	-	-
At December 31, 2021	1 284	310	2 540	231	13 989	427	-

14. INVENTORIES

($ millions)	December 31 2021	December 31 2020
Crude oil(1)	1 501	1 429
Refined products	1 820	1 322
Materials, supplies and merchandise	789	866
	4 110	3 617

(1) Includes $110 million of inventories held for trading purposes (2020 – $154 million), which are measured at fair value less costs to sell based on Level 1 and Level 2 fair value inputs.

During 2021, purchased product inventories of $14.7 billion (2020 – $9.4 billion) were recorded as an expense.

15. PROPERTY, PLANT AND EQUIPMENT

($ millions)	Oil and Gas Properties	Plant and Equipment	Total
Cost			
At December 31, 2019	40 596	84 568	125 164
Additions	820	2 994	3 814
Transfers from exploration and evaluation	170	-	170
Changes in decommissioning and restoration	1 078	3	1 081
Disposals and derecognition	(9)	(2 528)	(2 537)
Foreign exchange adjustments	54	(88)	(34)
At December 31, 2020	42 709	84 949	127 658
Additions	755	3 901	4 656
Transfers from exploration and evaluation	-	-	-
Changes in decommissioning and restoration	(1 127)	(5)	(1 132)
Disposals and derecognition	(1 902)	(2 652)	(4 554)
Foreign exchange adjustments	(118)	49	(69)
At December 31, 2021	40 317	86 242	126 559
Accumulated provision			
At December 31, 2019	(22 389)	(30 135)	(52 524)
Depreciation, depletion, amortization and impairment	(3 039)	(6 166)	(9 205)
Disposals and derecognition	-	2 205	2 205
Foreign exchange adjustments	(45)	41	(4)
At December 31, 2020	(25 473)	(34 055)	(59 528)

Depreciation, depletion, amortization and impairment	**(1 216)**	**(4 465)**	**(5 681)**
Disposals and derecognition	**1 676**	**2 452**	**4 128**
Foreign exchange adjustments	**70**	**(2)**	**68**
At December 31, 2021	**(24 943)**	**(36 070)**	**(61 013)**
Net property, plant and equipment			
December 31, 2020	17 236	50 894	68 130
December 31, 2021	**15 374**	**50 172**	**65 546**

	December 31, 2021			December 31, 2020		
($ millions)	Cost	Accumulated Provision	Net Book Value	Cost	Accumulated Provision	Net Book Value
Oil Sands	**87 849**	**(37 971)**	**49 878**	86 999	(35 059)	51 940
Exploration and Production	**21 495**	**(15 999)**	**5 496**	23 640	(17 424)	6 216
Refining and Marketing	**15 989**	**(6 596)**	**9 393**	15 757	(6 547)	9 210
Corporate and Eliminations	**1 226**	**(447)**	**779**	1 262	(498)	764
	126 559	**(61 013)**	**65 546**	127 658	(59 528)	68 130

At December 31, 2021, the balance of assets under construction and not subject to depreciation or depletion was $ 4.6 billion (December 31, 2020 – $5.0 billion).

16. ASSET IMPAIRMENTS

Oil Sands

Fort Hills assets:

During the fourth quarter of 2021, the company performed an asset impairment test on its Fort Hills cash generating unit (CGU) due to changes in its mine plan. The impairment test was performed using recoverable amounts based on fair value less cost of disposal. An expected cash flow approach was used with the following asset-specific assumptions (Level 3 fair value inputs note 27):

- Western Canada Select (WCS) price forecast of US$55.00/bbl in 2022, US$54.57/bbl in 2023, and an average price of US$50.86/bbl between 2024 and 2031, escalating at 2% per year thereafter over the life of the project up to 2058, adjusted for asset-specific location and quality differentials;
- the company's share of production ranging from 94,000 to 111,000 bbls/d over the life of the project;
- cash operating costs averaging $22.00/bbl to $23.00/bbl over the life of the project (expressed in real dollars), which reflects operating, selling and general expenses adjusted for non-production costs, including share-based compensation, research costs, and excess power revenue;
- foreign exchange rate of US$0.80 per one Canadian dollar; and
- risk-adjusted discount rate of 7.5% (after-tax).

Factors including an improved WCS price forecast in the next two years and optimization of the mine plan to exclude high strip ratio zones were offset by higher operating and capital costs. The recoverable amount of the Fort Hills CGU was $5.5 billion as at December 31, 2021, which indicated that no impairment loss or reversal was required.

The recoverable amount estimate is most sensitive to price and discount rate. A 5% average decrease in price over the life of the project would have resulted in an impairment charge of approximately $1.0 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 impairment charge of approximately $ 0.5 billion (after-tax) on the company's share of the Fort Hills assets.

Exploration and Production

Terra Nova assets:

During the third quarter of 2021, the company finalized an agreement with the co-owners of the Terra Nova Project to restructure the project ownership and move forward with the Asset Life Extension Project. The agreement increased the company's working interest to 48% (previously approximately 38%) and includes royalty and financial support from the Government of Newfoundland and Labrador. The company received $26 million (net of taxes of $8 million) in cash consideration to acquire the additional 10% working interest, which was primarily allocated to the asset retirement obligation and property, plant and equipment of the project. As a result of these events, during the third quarter of 2021, the company performed an impairment reversal test on the Terra Nova CGU as the recoverable amount of this CGU was sensitive to the financial support from the Government of Newfoundland and Labrador and revised royalty structure resulting in increased profitability and economic value. The impairment reversal test was 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 27).

As a result of the impairment reversal test, the recoverable amounts were determined to be greater than the carrying values of the Terra Nova CGU and the company recorded an impairment reversal of $168 million (net of taxes of $53 million) on its share of the Terra Nova assets in the Exploration and Production segment in the third quarter of 2021. In addition to the financial support from the government, the recoverable amount was determined based on the following asset-specific assumptions:

- Brent price forecast of US$65.00/bbl in 2023 and US$68.00/bbl in 2024, escalating at 2% per year thereafter over the life of the project to 2033 and adjusted for asset-specific location and quality differentials;
- the anticipated return to operations before the end of 2022 and the company's share of production of approximately 6,000 bbls/d (based on its previous 38% working interest) over the life of the project; and
- risk-adjusted discount rate of 9.0% (after-tax).

The recoverable amount of the Terra Nova CGU was $177 million as at September 30, 2021.

No indicators of impairment or reversals of impairment were identified as at December 31, 2021.

Asset Impairments in 2020

The COVID-19 pandemic has resulted in a significant decrease in global demand for crude oil and commodity prices. In response, the company announced plans to reduce capital and operating costs. As a result of these events, the company performed asset impairment tests on certain CGUs in its Oil Sands and Exploration and Production segments as at March 31, 2020 as the recoverable amounts of these CGUs were most sensitive to the combined reduction in crude oil prices and changes to their respective capital and operating plans.

During the fourth quarter of 2020, the Fort Hills partners approved an earlier date for the phased restart of the second primary extraction train, compared to what was assumed in the first quarter impairment test. As such, the company performed an impairment reversal assessment as at December 31, 2020. Further, as there is significant doubt on the future of the West White Rose (WWR) Project, the company also performed an impairment test for the White Rose CGU as at December 31, 2020. 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 27):

Oil Sands

The company performed an impairment reversal assessment for the Fort Hills CGU using the following asset-specific assumptions at December 31, 2020:

- Western Canadian Select (WCS) price forecast of US$32.00/bbl in 2021, US$41.15/bbl in 2022, US$47.50/bbl in 2023 and US$49.50/bbl in 2024, escalating at approximately 2% per year thereafter over the life of the project up to 2064, adjusted for asset-specific location and quality differentials;

- the company's share of production averaging 74,000 bbls/d through 2022 while the Fort Hills Project operates on two primary extraction trains but at a reduced capacity, and then ranging from 97,000 to 105,000 bbls/d over the remaining life of the project;

- cash operating costs averaging $25.50/bbl through 2022 while the Fort Hills Project operates on two primary extraction trains but at a reduced capacity, and then ranging from $19.00/bbl to $23.00/bbl thereafter as the project returns to full capacity over the remaining life of the project (expressed in real dollars). Cash operating costs reflect operating, selling and general expense adjusted for non-production costs, including share-based compensation, research costs, and excess power revenue;

- foreign exchange rate of US$0.76 per one Canadian dollar in 2021, and US $0.80 per one Canadian dollar thereafter; and

- risk-adjusted discount rate of 7.5% (after-tax).

Positive factors, including an increase to forecast production as a result of the restart of the second primary extraction train, improved the WCS price forecast in the next two years, and lower operating costs were offset by lower long-term prices and the negative impact from a strengthening Canadian dollar. The recoverable amount of the Fort Hills CGU was $5.7 billion as at December 31, 2020, which indicated that no impairment reversal was required.

The recoverable amount estimate is most sensitive to price and discount rate. A 5% average increase in price over the life of the project would have resulted in an impairment reversal amount of approximately $1.0 billion (after-tax) on the company's share of the Fort Hills assets. A 1% decrease in the discount rate would have resulted in an impairment reversal amount of approximately $ 0.9 billion (after-tax) on the company's share of the Fort Hills assets.

During the first quarter of 2020, the company recorded an impairment of $ 1.38 billion (net of taxes of $ 0.44 billion) on its share of the Fort Hills Project in the Oil Sands segment using the following asset-specific assumptions:

- WCS price forecast of US$9.00/bbl for the remainder of 2020, US$13.60/bbl in 2021, US$32.00/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 2061, adjusted for asset-specific location and quality differentials;

- the company's share of production of 47,000 bbls/d while the Fort Hills Project operates on one primary extraction train for the remainder of 2020 through to 2021, and ramping up to two primary extraction trains during 2022, and then ranging from 96,000 to 106,000 bbls/d over the remaining life of the project;

- cash operating costs averaging $32.00/bbl to $37.00/bbl while the Fort Hills Project operates on one primary extraction train for the remainder of 2020 through to 2021, and ranging from $22.00/bbl to $24.00/bbl thereafter, as the project returns to two primary extraction trains over the remaining life of the project (expressed in real dollars). Cash operating costs reflect operating, selling and general expense adjusted for non-production costs, including share-based compensation, research costs, and excess power revenue;

- foreign exchange rate of US$0.76 per one Canadian dollar; and

- risk-adjusted discount rate of 7.5% (after-tax).

The recoverable amount of the Fort Hills CGU was $ 6.4 billion as at March 31, 2020. The recoverable amount estimate is most sensitive to price and discount rate. A 5% average decrease in price over the life of the project would have resulted in an increase to the impairment charge of approximately $1.1 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 $1.1 billion (after-tax) on the company's share of the Fort Hills assets.

Exploration and Production

White Rose assets:

In the fourth quarter of 2020, the company reassessed the likelihood of completing the West White Rose (WWR) Project. As a result of this reassessment, the company performed an impairment test of the White Rose CGU. While the base White Rose

Project will continue to produce in 2021, the company has removed the reserves and forecast revenues for the WWR Project. This decision reduced planned production from the CGU and increased the expected closure costs relative to the assumptions used in the first quarter of 2020, with all other assumptions remaining relatively consistent. An after-tax impairment charge of $423 million (net of taxes of $136 million) was recognized and the White Rose CGU is fully impaired as at December 31, 2020.

During the first quarter of 2020, the company recorded an impairment of $137 million (net of taxes of $45 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$30.00/bbl for the remainder of 2020, US$35.00/bbl in 2021, US$50.00/bbl in 2022 and US$69.00/bbl in 2023, escalating at 2% per year thereafter over the life of the project to 2036 and adjusted for asset-specific location and quality differentials;
- the company's share of production of approximately 9,800 bbls/d over the life of the project;
- the company's share of future capital expenditures of $1.435 billion, including the WWR expansion; and
- risk-adjusted discount rate of 9.0% (after-tax).

The recoverable amount of the White Rose CGU was $185 million as at March 31, 2020. The recoverable amount estimate was most sensitive to price and discount rate. A 5% average decrease in price over the life of the project would have resulted in an increase to the impairment charge of approximately $83 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 $45 million (after-tax) on the company's share of the White Rose assets.

Terra Nova assets:

During the first quarter of 2020, the company recorded an impairment of $285 million (net of taxes of $93 million) on its share of the Terra Nova assets in the Exploration and Production segment using the following asset-specific assumptions:

- Brent price forecast of US$30.00/bbl for the remainder of 2020, US$35.00/bbl in 2021, US$50.00/bbl in 2022 and US$69.00/bbl in 2023, escalating at 2% per year thereafter over the life of the project to 2031 and adjusted for asset-specific location and quality differentials;
- the company's share of production of approximately 6,200 bbls/d over the life of the project, including the benefit of the asset life extension project; and
- risk-adjusted discount rate of 9.0% (after-tax).

The recoverable amount of the Terra Nova CGU was $24 million as at March 31, 2020.

No indicators of impairment or reversals of impairment were identified as at December 31, 2020.

17. RIGHT-OF-USE ASSETS AND LEASES

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

($ millions)	December 31 2021	December 31 2020
Property, plant and equipment, net – excluding ROU assets	**62 821**	65 306
ROU assets	**2 725**	2 824
	65 546	68 130

The following table presents the ROU assets by asset class:

($ millions)	Plant and Equipment
Cost	
At January 1, 2020	3 505
Additions and adjustments	312
Disposals	(25)
Foreign exchange	(6)
At December 31, 2020	3 786
Additions and adjustments	**307**
Disposals	**(232)**
Foreign exchange	**-**
At December 31, 2021	**3 861**
Accumulated provision	
At January 1, 2020	(610)
Depreciation	(375)
Disposals	21
Foreign exchange	2
At December 31, 2020	(962)
Depreciation	**(396)**
Disposals	**221**
Foreign exchange	**1**
At December 31, 2021	**(1 136)**
Net ROU assets	
At December 31, 2020	2 824
At December 31, 2021	**2 725**

Other lease-related items recognized in the Consolidated Statements of Comprehensive Income (Loss):

($ millions)	For the year ended December 31 2021	2020
Operating, selling and general		
Short-term lease expense	**143**	181
Variable lease expense	**35**	39

There were no leases with residual value guarantees. For the year ended December 31, 2021, total cash outflow for leases, excluding short-term lease expense and variable lease expense, was $486 million (2020 – $501 million).

18. EXPLORATION AND EVALUATION ASSETS

($ millions)	December 31 2021	December 31 2020
Beginning of year	**2 286**	2 428
Acquisitions and additions	**2**	176
Transfers to oil and gas assets	**-**	(170)
Dry hole expenses	**-**	(80)
Disposals and derecognition	**(54)**	(70)
Foreign exchange adjustments	**(8)**	2
End of year	**2 226**	2 286

19. OTHER ASSETS

($ millions)	December 31 2021	December 31 2020
Investments	**391**	323
Prepaids and other	**916**	954
	1 307	1 277

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 and are unlikely to be settled within one year.

20. GOODWILL AND OTHER INTANGIBLE ASSETS

($ millions)	Oil Sands Goodwill	Refining and Marketing Goodwill	Other Intangibles	Total
At December 31, 2019	2 752	140	166	3 058
Additions	-	-	272	272
Amortization	-	-	(2)	(2)
At December 31, 2020	2 752	140	436	3 328
Additions	**-**	**-**	**213**	**213**
Amortization	**-**	**-**	**(18)**	**(18)**
At December 31, 2021	**2 752**	**140**	**631**	**3 523**

The company performed a goodwill impairment test at December 31, 2021 on its Oil Sands segment. Recoverable amounts were based on fair value less costs of disposal calculated using the present value of the segment's expected future cash flows.

Cash flow forecasts are based on past experience, historical trends, third-party evaluations of the company's reserves and resources to determine production profiles and volumes, and estimates of operating costs, maintenance and capital expenditures. These estimates 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 climate change, long-term forecasts of commodity prices, inflation rates, foreign exchange rates and discount rates specific to the CGU (Level 3 fair value inputs)

Future cash flow estimates are discounted using after-tax risk-adjusted discount rates. The after-tax discount rate applied to cash flow projections was 7.5% (2020 – 7.5%). The company based its cash flow projections on a West Texas Intermediate price of US$71.00/bbl in 2022, US$66.81/bbl in 2023, US$63.46/bbl in 2024, US$64.73/bbl in 2025 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 50 years to 55 years based on the respective CGU. As a result of this analysis, management did not identify any impairment of goodwill within 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. As a result of this analysis, management did not identify any impairment of goodwill within the Refining and Marketing segment.

21. DEBT AND CREDIT FACILITIES

Debt and credit facilities are comprised of the following:

Short-Term Debt

($ millions)	**December 31 2021**	December 31 2020
Commercial paper[1]	1 284	3 566

(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, 2021 was 0.33% (December 31, 2020 - 0.39%).

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Long-Term Debt

($ millions)	December 31 2021	December 31 2020
Fixed-term debt[2][3]		
3.10% Series 5 Medium Term Notes, due 2021	**-**	748
9.25% Debentures, due 2021 (US$300)	**-**	389
9.40% Notes, due 2021 (US$220)[4][5]	**-**	281
4.50% Notes, due 2022 (US$182)[4]	**231**	224
2.80% Notes, due 2023 (US$450)	**569**	574
3.60% Notes, due 2024 (US$750)	**-**	953
3.10% Notes, due 2025 (US$550)	**696**	701
3.00% Series 5 Medium Term Notes, due 2026	**699**	699
7.875% Debentures, due 2026 (US$275)	**359**	364
8.20% Notes, due 2027 (US$59)[4]	**78**	79
7.00% Debentures, due 2028 (US$250)	**320**	323
3.10% Series 6 Medium Term Notes, due 2029	**748**	748
5.00% Series 7 Medium Term Notes, due 2030	**1 247**	1 247
7.15% Notes, due 2032 (US$500)	**631**	637
5.35% Notes, due 2033 (US$300)	**355**	356
5.95% Notes, due 2034 (US$500)	**630**	636
5.95% Notes, due 2035 (US$600)	**731**	736
5.39% Series 4 Medium Term Notes, due 2037	**599**	599
6.50% Notes, due 2038 (US$1 150)	**1 451**	1 464
6.80% Notes, due 2038 (US$900)	**1 156**	1 167
6.85% Notes, due 2039 (US$750)	**946**	953
6.00% Notes, due 2042 (US$152)[4]	**149**	149
4.34% Series 5 Medium Term Notes, due 2046	**300**	300
4.00% Notes, due 2047 (US$750)	**945**	952
3.95% Series 8 Medium Term Notes, due 2051	**493**	-
3.75% Notes, due 2051 (US$750)	**945**	-
Total unsecured long-term debt	**14 278**	15 279
Lease liabilities[6]	**2 850**	2 908
Deferred financing costs	**(58)**	(54)
	17 070	18 133
Current portion of long-term debt and lease liabilities		
Lease liabilities	**(310)**	(272)
Long-term debt	**(231)**	(1 413)
	(541)	(1 685)
Total long-term lease liabilities	**2 540**	2 636
Total long-term debt	**13 989**	13 812

(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) Interest rates range from 0.4% to 14.2% and maturity dates range from 2022 to 2062.

Subsequent to the fourth quarter of 2021, the company completed an early redemption of its outstanding US $182 million 4.50% notes, originally scheduled to mature in the second quarter of 2022.

During the fourth quarter of 2021, the company repaid its US$ 300 million (book value of $371 million) senior unsecured notes at maturity with a coupon of 9.25%, for US$314 million ($388 million), including US$14 million ($17 million) of accrued interest.

In the third quarter of 2021, the company completed an early redemption of its US$ 750 million (book value of $951 million) senior unsecured notes with a coupon interest of 3.60% originally scheduled to mature on December 1, 2024, for US$ 822 million ($1.0 billion), including US$9 million ($11 million) of accrued interest, resulting in a debt extinguishment loss of $ 80 million ($60 million after tax).

On March 4, 2021, the company issued US$ 750 million of senior unsecured notes maturing on March 4, 2051. The notes have a coupon of 3.75% and were priced at US$ 99.518 per US$100 principal amount for an effective yield of 3.777%. The company also issued $500 million of senior unsecured Series 8 medium-term notes on March 4, 2021, maturing on March 4, 2051. The notes have a coupon of 3.95% and were priced at $ 98.546 per $100 principal amount for an effective yield of 4.034%. Interest on the 3.75% and 3.95% notes is paid semi-annually.

In the first quarter of 2021, the company completed an early redemption of its $ 750 million senior unsecured Series 5 medium-term notes with a coupon of 3.10%, originally scheduled to mature on November 26, 2021, for $770 million, including $8 million of accrued interest, resulting in a debt extinguishment loss of $12 million ($9 million after-tax). The company also completed an early redemption of its US$220 million (book value of $278 million) senior unsecured notes with a coupon of 9.40%, originally scheduled to mature on September 1, 2021, for US$230 million ($290 million), including US$2 million ($2 million) of accrued interest, resulting in a debt extinguishment loss of $10 million ($8 million after-tax).

In 2020, the company issued $1.25 billion of senior unsecured Series 7 Medium Term Notes maturing on April 9, 2030. The Series 7 Medium Term Notes have a coupon of 5.00% and were priced at $99.697 per $100 principal amount for an effective yield of 5.039%. Interest on the Series 7 Medium Term Notes is paid semi-annually.

In 2020, the company issued US $450 million of senior unsecured notes maturing on May 15, 2023. The notes have a coupon of 2.80% and were priced at US $99.903 per US$100 principal amount for an effective yield of 2.834%. The company also issued US$550 million of senior unsecured notes in 2020 maturing on May 15, 2025. The notes have a coupon of 3.10% and were priced at US$99.949 per US$100 principal amount for an effective yield of 3.111%. Interest on the 2.80% and 3.10% notes is paid semi-annually.

Scheduled Debt Repayments

Scheduled principal repayments as at December 31, 2021 for lease liabilities, short-term debt and long-term debt are as follows:

($ millions)	Repayment
2022	1 816
2023	828
2024	232
2025	907
2026	1 244
Thereafter	13 482
	18 509

Credit Facilities

In the second quarter of 2021, the company reduced the size of each tranche of its syndicated credit facilities by US$ 500 million and $500 million to US$2.0 billion and $3.0 billion, respectively, and extended the maturity from April 2022 and April 2023 to June 2024 and June 2025, respectively.

Effective March 5, 2021, the company terminated $2.8 billion of bilateral credit facilities as these credit facilities were no longer required. The terminated credit facilities had a two-year term and were entered into in March and April 2020 to ensure access to adequate financial resources in connection with the COVID-19 pandemic should they have been required.

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

($ millions)	2021
Fully revolving and expires in 2025	**3 000**
Fully revolving and expires in 2024	**2 531**
Can be terminated at any time at the option of the lenders	**1 420**
Total credit facilities	**6 951**
Credit facilities supporting outstanding commercial paper	**(1 284)**
Credit facilities supporting standby letters of credit	**(1 147)**
Total unutilized credit facilities (1)	**4 520**

(1) Available credit facilities for liquidity purposes at December 31, 2021 decreased to $4.247 billion, compared to $6.043 billion at December 31, 2020.

22. OTHER LONG-TERM LIABILITIES

($ millions)	December 31 2021	December 31 2020
Pensions and other post-retirement benefits (note 23)	**1 207**	2 004
Share-based compensation plans (note 26)	**291**	143
Partnership liability (note 27) (1)	**427**	436
Deferred revenue	**29**	35
Libya Exploration and Production Sharing Agreement (EPSA) signature bonus (2)	**74**	74
Other	**152**	148
	2 180	2 840

(1) The company paid $60 million in 2021 (2020 – $62 million) in distributions to the partners of the East Tank Farm Development, of which $51 million (2020 – $52 million) was allocated to interest expense and $9 million (2020 – $10 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, 2021, the carrying amount of the Libya EPSAs' signature bonus was $78 million (December 31, 2020 – $78 million). The current portion is $4 million (December 31, 2020 – $4 million) and is recorded in Accounts Payable and Accrued Liabilities.

23. 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. plans 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 2021	Pension Benefits 2020	Other Post-Retirement Benefits 2021	Other Post-Retirement Benefits 2020
Change in benefit obligation				
Benefit obligation at beginning of year	**8 682**	7 708	**690**	631
Current service costs	**302**	272	**19**	15
Plan participants' contributions	**17**	17	**-**	-
Benefits paid	**(350)**	(316)	**(27)**	(24)
Interest costs	**222**	238	**18**	19
Foreign exchange	**(6)**	1	**-**	-
Settlements	**11**	5	**-**	-
Actuarial remeasurement:				
Experience gain arising on plan liabilities	**(1)**	(26)	**(1)**	(6)
Actuarial (gain) loss arising from changes in demographic assumptions	**(2)**	50	**-**	12
Actuarial (gain) loss arising from changes in financial assumptions	**(572)**	733	**(27)**	43
Benefit obligation at end of year	**8 303**	8 682	**672**	690
Change in plan assets				
Fair value of plan assets at beginning of year	**7 305**	6 693	**-**	-
Employer contributions	**(11)**	132	**-**	-
Plan participants' contributions	**17**	17	**-**	-
Benefits paid	**(325)**	(290)	**-**	-
Foreign exchange	**(5)**	(1)	**-**	-
Settlements	**11**	5	**-**	-
Administrative costs	**(2)**	(2)	**-**	-
Income on plan assets	**181**	203	**-**	-
Actuarial remeasurement:				
Return on plan assets greater than discount rate	**530**	548	**-**	-
Fair value of plan assets at end of year	**7 701**	7 305	**-**	-
Net unfunded obligation	**602**	1 377	**672**	690

In June 2020, the Government of Alberta issued an amendment to the Employment Pension Plans Regulation to provide additional forms of relief to administrators of Alberta-registered pension plans. The amendment allowed for a temporary increase to the limit of funding excess to reduce or eliminate current service contributions for a single fiscal year for purposes of a contribution holiday. The company was approved for funding relief starting in late 2020 for both the defined benefit plan and the defined contribution plan based on funding levels in the defined benefit plan. In 2021, employer contributions reflect the contribution holiday and a transfer of funds from the defined benefit plan to the defined contribution plan, with the company resuming cash contributions near the end of the year. The company expects to make cash contributions to its defined benefit pension plans in 2022 of $189 million.

Of the total net unfunded obligations as at December 31, 2021, 98% relates to Canadian pension plans and other post-retirement benefits obligation (December 31, 2020 – 96%). The weighted average duration of the defined benefit obligation under the Canadian pension plans and other post-retirement plans is 15.1 years (2020 – 15.8 years).

The net unfunded obligation is recorded in Accounts Payable and Accrued Liabilities and Other Long-Term Liabilities (note 22) in the Consolidated Balance Sheets.

($ millions)	Pension Benefits 2021	2020	Other Post-Retirement Benefits 2021	2020
Analysis of amount charged to earnings:				
Current service costs	**302**	272	**19**	15
Interest costs	**41**	35	**18**	19
Defined benefit plans expense	**343**	307	**37**	34
Defined contribution plans expense	**94**	83	**-**	-
Total benefit plans expense charged to earnings	**437**	390	**37**	34

Components of defined benefit costs recognized in Other Comprehensive Income:

($ millions)	Pension Benefits 2021	2020	Other Post-Retirement Benefits 2021	2020
Return on plan assets (excluding amounts included in net interest expense)	**(530)**	(548)	**-**	-
Actuarial (gain) arising from experience on plan liabilities	**(1)**	(26)	**(1)**	(6)
Actuarial (gain) loss arising from changes in financial assumptions	**(572)**	733	**(27)**	43
Actuarial (gain) loss arising from changes in demographic assumptions	**(2)**	50	**-**	12
Actuarial (gain) loss recognized in other comprehensive income	**(1 105)**	209	**(28)**	49

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 2021	December 31 2020	Other Post-Retirement Benefits December 31 2021	December 31 2020
Discount rate	**2.90**	2.50	**2.90**	2.50
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 that the health care costs would increase annually by 5%.

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	(24)	31
Effect on the benefit obligations	(1 155)	1 515

($ millions)	Other Post-Retirement Benefits Increase	Other Post-Retirement Benefits Decrease
1% change in discount rate		
Effect on the benefit obligations	(80)	99
1% change in health care cost		
Effect on the aggregate service and interest costs	1	(1)
Effect on the benefit obligations	36	(31)

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:

(%)	2021	2020
Equities	**48**	50
Fixed income	**38**	38
Plan assets, comprised of:		
– Real Estate	**14**	12
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.

24. PROVISIONS

($ millions)	Decommissioning and Restoration[1]	Royalties	Other[2]	Total
At December 31, 2019	8 898	133	276	9 307
Liabilities incurred	967	16	190	1 173
Change in discount rate	402	-	-	402
Changes in estimates	(268)	(71)	5	(334)
Liabilities settled	(231)	(7)	(4)	(242)
Accretion	278	-	-	278
Foreign exchange	(2)	-	-	(2)
At December 31, 2020	10 044	71	467	10 582
Less: current portion	(250)	(71)	(206)	(527)
	9 794	-	261	10 055
At December 31, 2020	10 044	71	467	10 582
Liabilities incurred	**104**	**137**	**171**	**412**
Change in discount rate	**(1 260)**	**-**	**-**	**(1 260)**
Changes in estimates	**(76)**	**(12)**	**(13)**	**(101)**
Liabilities settled	**(263)**	**26**	**(84)**	**(321)**
Accretion	**304**	**-**	**-**	**304**
Asset disposals	**(61)**	**-**	**-**	**(61)**
Foreign exchange	**-**	**-**	**-**	**-**
At December 31, 2021	**8 792**	**222**	**541**	**9 555**
Less: current portion	**(266)**	**(222)**	**(291)**	**(779)**
	8 526	**-**	**250**	**8 776**

(1) Represents decommissioning and restoration provisions associated with the retirement of Property, Plant and Equipment and Exploration and Evaluation assets. The total undiscounted and uninflated amount of estimated future cash flows required to settle the obligations at December 31, 2021 was approximately $13.8 billion (December 31, 2020 – $14.1 billion). A weighted average credit-adjusted risk-free interest rate of 3.70% was used to discount the provision recognized at December 31, 2021 (December 31, 2020 – 3.10%). 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. It also includes a provision, with the offset being recorded to transportation expense, for $187 million (after-tax $142 million) related to the Keystone XL pipeline project and a restructuring provision remaining for $88 million.

Sensitivities

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

As at December 31	**2021**	2020
1% Increase	**(1 497)**	(1 919)
1% Decrease	**2 113**	2 806

25. 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.

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Normal Course Issuer Bid

During the first quarter of 2021, the company announced its intention to commence a new Normal Course Issuer Bid (the 2021 NCIB) to repurchase common shares through the facilities of the Toronto Stock Exchange (TSX), New York Stock Exchange (NYSE) and/or alternative trading systems. Pursuant to the 2021 NCIB, the company may repurchase for cancellation up to 44,000,000 common shares between February 8, 2021, and February 7, 2022.

During the third quarter of 2021, Suncor received approval from the TSX to amend the 2021 NCIB effective as of the close of markets on July 30, 2021. The amended notice provides that Suncor may increase the maximum number of common shares that may be repurchased under the 2021 NCIB from February 8, 2021, and ending February 7, 2022, from 44,000,000 common shares, or approximately 2.9% of Suncor's issued and outstanding common shares as at January 31, 2021, to 76,250,000 common shares, or approximately 5% of Suncor's issued and outstanding common shares as at January 31, 2021. No other terms of the NCIB were amended.

During the fourth quarter of 2021, Suncor received approval from the TSX to amend its existing NCIB effective as of the close of markets on October 29, 2021. The notice provides that Suncor may increase the maximum number of common shares that may be repurchased in the period beginning February 8, 2021, and ending February 7, 2022, from 76,250,000 shares, or approximately 5% of Suncor's issued and outstanding common shares as at January 31, 2021, to 106,700,000, or approximately 7% of Suncor's public float as at January 31, 2021. No other terms of the NCIB have been amended.

For the twelve months ended December 31, 2021, the company repurchased 84.0 million common shares under the 2021 NCIB at an average price of $27.45 per share, for a total repurchase cost of $ 2.3 billion.

Subsequent to the fourth quarter of 2021, the TSX accepted a notice filed by Suncor to renew its NCIB to purchase the company's common shares through the facilities of the TSX, NYSE and/or alternative trading systems. The notice provides that, beginning February 8, 2022, and ending February 7, 2023, Suncor may purchase for cancellation up to 71,650,000 common shares, which is equal to approximately 5% of Suncor's issued and outstanding common shares as at the date hereof. As at January 31, 2022, Suncor had 1,435,748,494 common shares issued and outstanding.

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

($ millions, except as noted)	**2021**	2020
Share repurchase activities (thousands of common shares)		
Shares repurchased	**83 959**	7 527
Amounts charged to		
Share capital	**1 382**	124
Retained earnings	**922**	183
Share repurchase cost	**2 304**	307
Average repurchase cost per share	**27.45**	40.83

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 2021**	December 31 2020
Amounts charged to		
Share capital	**120**	-
Retained earnings	**110**	-
Liability for share purchase commitment	**230**	-

26. 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)	2021	2020
Equity-settled plans	**21**	32
Cash-settled plans	**301**	(28)
Total share-based compensation expense	**322**	4

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)	December 31 2021	December 31 2020
Current liability	**153**	117
Long-term liability (note 22)	**291**	143
Total Liability	**444**	260

The intrinsic value of the vested awards at December 31, 2021 was $ 200 million (December 31, 2020 – $149 million).

Stock Option Plans

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

Stock options granted by the company provide the holder with the right to purchase common shares at the market price on the grant date, subject to fulfilling vesting terms. 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:

	2021	2020
Annual dividend per share (dollars)	**1.05**	1.10
Risk-free interest rate	**0.49%**	1.35%
Expected life	**5 years**	5 years
Expected volatility	**40%**	24%
Weighted average fair value per option (dollars)	**5.40**	4.51

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.

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

	2021		2020	
	Number (thousands)	**Weighted Average Exercise Price ($)**	Number (thousands)	Weighted Average Exercise Price ($)
Outstanding, beginning of year	**38 373**	**39.65**	33 882	39.70
Granted	**3 457**	**22.71**	6 341	38.95
Exercised as options for common shares	**(245)**	**29.82**	(804)	35.73
Forfeited/expired	**(4 495)**	**37.62**	(1 046)	39.91
Outstanding, end of year	**37 090**	**38.39**	38 373	39.65
Exercisable, end of year	**28 421**	**39.87**	26 943	39.10

For the options outstanding at December 31, 2021, 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 ($)
22.63-24.99	**3 378**	6	22.65	**30**	22.88
25.00-29.99	**9**	6	29.29	—	—
30.00-34.99	**4 694**	1	30.23	**4 672**	30.23
35.00-39.99	**9 537**	3	38.99	**6 024**	38.95
40.00-44.99	**19 292**	3	42.71	**17 516**	42.68
45.00-49.99	**52**	4	48.15	**51**	48.16
50.00-54.27	**128**	3	52.39	**128**	52.39
Total	**37 090**	3	38.39	**28 421**	39.87

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

(thousands)	2021	2020
	25 037	8 999

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.

In 2022, Syncrude's Long Term Incentive Plans (LTIP) of approximately $ 123 million will be converted into Suncor RSUs at a conversion price of $30.93.

(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, 2019	2 193	13 602	1 287
Granted	1 232	6 567	289
Redeemed for cash	(1 086)	(4 707)	(191)
Forfeited/expired	(54)	(367)	-
Outstanding, December 31, 2020	2 285	15 095	1 385
Granted	**1 285**	**11 954**	**164**
Redeemed for cash	**(751)**	**(4 609)**	**(167)**
Forfeited/expired	**(53)**	**(1 003)**	**-**
Outstanding, December 31, 2021	**2 766**	**21 437**	**1 382**

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:

	2021		2020	
	Number (thousands)	**Weighted Average Exercise Price ($)**	Number (thousands)	Weighted Average Exercise Price ($)
Outstanding, beginning of year	**509**	**39.25**	385	39.83
Granted	**10**	**22.63**	132	37.41
Exercised	**—**	**—**	(7)	36.38
Forfeited/expired	**(56)**	**37.78**	(1)	39.08
Outstanding, end of year	**463**	**39.06**	509	39.25
Exercisable, end of year	**357**	**39.68**	307	39.09

27. 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, 2021, the carrying value of fixed-term debt accounted for under amortized cost was $14.2 billion (December 31, 2020 – $15.2 billion) and the fair value at December 31, 2021 was $ 17.4 billion (December 31, 2020 – $18.8 billion). The decrease in carrying value and fair value of debt is mainly due to repayment of debt 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, 2021, the carrying value of the Partnership liability accounted for under amortized cost was $436 million (December 31, 2020 – $445 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)	2021	2020
Fair value outstanding, beginning of year	**(121)**	(39)
Cash settlements – paid (received) during the year	**178**	(257)
Changes in fair value recognized in earnings during the year (note 7)	**(155)**	175
Fair value outstanding, end of year	**(98)**	(121)

(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, 2021, 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 measured at fair value for each hierarchy level as at December 31, 2021 and 2020.

($ millions)	Level 1	Level 2	Level 3	Total Fair Value
Accounts receivable	63	90	-	153
Accounts payable	(202)	(72)	-	(274)
Balance at December 31, 2020	(139)	18	-	(121)
Accounts receivable	**35**	**88**	**-**	**123**
Accounts payable	**(134)**	**(87)**	**-**	**(221)**
Balance at December 31, 2021	**(99)**	**1**	**-**	**(98)**

During the year ended December 31, 2021, 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, 2021 and 2020.

Financial Assets

($ millions)	Gross Assets	Gross Liabilities Offset	Net Amounts Presented
Fair value of derivative assets	2 890	(2 737)	153
Accounts receivable	2 999	(1 398)	1 601
Balance at December 31, 2020	5 889	(4 135)	1 754
Fair value of derivative assets	**6 527**	**(6 404)**	**123**
Accounts receivable	**5 048**	**(2 734)**	**2 314**
Balance at December 31, 2021	**11 575**	**(9 138)**	**2 437**

Financial Liabilities

($ millions)	Gross Liabilities	Gross Assets Offset	Net Amounts Presented
Fair value of derivative liabilities	(3 011)	2 737	(274)
Accounts payable	(2 385)	1 398	(987)
Balance at December 31, 2020	(5 396)	4 135	(1 261)
Fair value of derivative liabilities	**(6 625)**	**6 404**	**(221)**
Accounts payable	**(4 205)**	**2 734**	**(1 471)**
Balance at December 31, 2021	**(10 830)**	**9 138**	**(1 692)**

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.

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 and refined product prices (including pricing differentials for various product types) and, to a lesser extent, natural gas and electricity 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 and refined product prices during transportation and natural gas prices.

An increase of US$10/bbl of crude oil as at December 31, 2021 would increase pre-tax earnings for the company's outstanding derivative financial instruments by approximately $58 million (2020 – $95 million increase).

(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, 2021 would increase pre-tax earnings related to the company's U.S. dollar denominated long-term debt, commercial paper and working capital by approximately $133 million (2020 – $182 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, 2021, the company had no outstanding forward interest rate swaps. The weighted average interest rate on total debt, including lease liabilities, for the year ended December 31, 2021 was 5.0% (2020 – 5.3%).

The company's net earnings are sensitive to changes in interest rates on the floating rate portion of the company's debt, which are offset by cash balances. To the extent interest expense is not capitalized, if interest rates applicable to floating rate instruments increased by 1%, it is estimated that the company's pre-tax earnings would increase by approximately $ 9 million primarily due to a higher cash balance compared to the short-term debt balance (2020 – approximately $17 million decrease). This assumes that the amount and mix of fixed and floating rate debt remains unchanged from December 31, 2021. The proportion of floating interest rate exposure at December 31, 2021 was 7.0% of total debt outstanding (2020 – 16.4%).

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. The company's available credit facilities decreased by $2.0 billion during the year ended December 31, 2021, primarily due to the cancellation of $2.8 billion in bi-lateral credit facilities that were no longer required as they were entered into in March and April 2020 to ensure access to adequate financial resources in connection with the COVID-19 pandemic, and a reduction in the size of the company's syndicated credit facilities. Suncor's cash and cash equivalents and total credit facilities at December 31, 2021 were $2.2 billion and $7.0 billion, respectively. Of Suncor's $7.0 billion in total credit facilities, $4.5 billion were unutilized at December 31, 2021. In addition, Suncor has $ 4.50 billion of unused capacity under a Canadian debt shelf prospectus and an unused capacity of US$4.25 billion under a U.S. universal 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, 2020			
($ millions)	Trade and Other Payables(1)	Gross Derivative Liabilities(2)	Debt(3)	Lease Liabilities
Within one year	4 410	2 849	5 773	474
2 to 3 years	37	162	2 233	771
4 to 5 years	37	-	3 009	631
Over 5 years	-	-	17 834	2 779
	4 484	3 011	28 849	4 655

	December 31, 2021			
($ millions)	**Trade and Other Payables(1)**	**Gross Derivative Liabilities(2)**	**Debt(3)**	**Lease Liabilities**
Within one year	**6 282**	**6 466**	**2 253**	**459**
2 to 3 years	**37**	**159**	**2 015**	**779**
4 to 5 years	**37**	**-**	**3 127**	**660**
Over 5 years	**-**	**-**	**18 836**	**2 633**
	6 356	**6 625**	**26 231**	**4 531**

(1) Trade and other payables exclude net derivative liabilities of $221 million (2020 – $274 million).

(2) Gross derivative liabilities of $6.625 billion (2020 – $3.011 billion) are offset by gross derivative assets of $6.404 billion (2020 – $2.737 billion), resulting in a net amount of $221 million (2020 – $274 million).

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

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, and a credit rating and a maximum credit limit are assigned. The assessment process is outlined in the credit policy and considers both quantitative and qualitative factors. The company constantly monitors the exposure to any single customer or counterparty along with the financial position of the customer or counterparty. If it is deemed that a customer or counterparty has become materially weaker, the company will work to reduce the credit exposure and lower the assigned credit limit. Regular reports are generated to monitor credit risk and the Credit Committee meets quarterly to ensure compliance with the credit policy and review the exposures.

A substantial portion of the company's accounts receivable are with customers in the oil and gas industry and are subject to normal industry credit risk. While the industry has experienced credit downgrades due to the COVID-19 pandemic, Suncor has not been significantly affected as the majority of Suncor's customers are large and established downstream companies with investment grade credit ratings. At December 31, 2021, 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, 2021, the company's net exposure was $123 million (December 31, 2020 – $153 million).

28. 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 adjusted funds from operations (2) and total debt to total debt plus shareholders' equity.

Net debt to adjusted funds from operations (2) is calculated as short-term debt plus total long-term debt less cash and cash equivalents, divided by adjusted 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, 2021 and 2020. The company's financial measures, as set out in the following schedule, were unchanged from 2020. 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. Total debt to total debt plus shareholders' equity was 33.4% at December 31, 2021 and decreased due to lower debt levels and higher shareholders' equity as a result of increased net earnings. 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 2021**	December 31 2020
Components of ratios			
Short-term debt		**1 284**	3 566
Current portion of long-term debt		**231**	1 413
Current portion of long-term lease liabilities		**310**	272
Long-term debt		**13 989**	13 812
Long-term lease liabilities		**2 540**	2 636
Total debt(1)		**18 354**	21 699
Less: Cash and cash equivalents		**2 205**	1 885
Net debt(1)		**16 149**	19 814
Shareholders' equity		**36 614**	35 757
Total capitalization (total debt plus shareholders' equity)		**54 968**	57 456
Adjusted funds from operations (2)		**10 257**	3 876
Net debt to adjusted funds from operations	<3.0 times	**1.6**	5.1
Total debt to total debt plus shareholders' equity	20% - 35%	**33.4%**	37.8%

(1) Total debt and net debt are non-GAAP financial measures.

(2) Adjusted 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.

29. 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 % 2021**	Ownership % 2020
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
Syncrude[1]	Oil sands development	Canada	**58.74**	—
Non-operated:				
Syncrude[1]	Oil sands development	Canada	**—**	58.74
Exploration and Production				
Operated by Suncor:				
Terra Nova[2]	Oil and gas production	Canada	**48.00**	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[3]	Oil and gas production	United Kingdom	**—**	26.69
Hibernia and the Hibernia South Extension Unit[4]	Oil and gas production	Canada	**19.48-20.00**	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[5]	Oil and gas production	Canada	**26.13-27.50**	26.13-27.50

(1) Suncor became the operator of the Syncrude project effective September 30, 2021.

(2) In the third quarter of 2021, Suncor finalized an agreement with the co-owners of the Terra Nova Project to restructure the project ownership and move forward with the Asset Life Extension Project. The agreement increased the company's working interest to 48.00%.

(3) Suncor sold its 26.69% working interest in the Golden Eagle Area Development in the fourth quarter of 2021.

(4) In the first quarter of 2021, the first redetermination of the Hibernia South Extension Unit increased the company's interest by 0.29% (from 19.19% to approximately 19.48%).

(5) In the third quarter of 2021, Suncor entered into a conditional agreement to increase its interest by 12.50% to approximately 40.00% in the White Rose asset subject to the sanctioning of the West White Rose Project.

Joint Ventures and Associates

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

	Joint ventures		Associates	
($ millions)	**2021**	2020	**2021**	2020
Net earnings (loss)	**5**	(10)	**(2)**	9
Total comprehensive earnings (loss)	**5**	(10)	**(2)**	9
Carrying amount as at December 31	**63**	58	**66**	68

30. SUBSIDIARIES

Material subsidiaries, each of which is wholly owned, either directly or indirectly, by the company as at December 31, 2021 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.

31. 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 years ended December 31, 2021 and 2020 are as follows:

($ millions)	2021	2020
Sales[1]	**1 011**	458
Purchases	**247**	130
Accounts receivable	**70**	26
Accounts payable and accrued liabilities	**17**	16

(1) Includes sales to Petroles Cadeko Inc. of $411 million (2020 - $93 million) and Parachem Chemicals Inc. of $343 million (2020 – $173 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)	2021	2020
Salaries and other short-term benefits	**8**	9
Pension and other post-retirement benefits	**3**	3
Share-based compensation	**47**	(9)
	58	3

32. 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)	2022	2023	2024	2025	2026	Thereafter	**Total**
Commitments							
Product transportation and storage	1 150	1 210	1 211	1 128	1 135	7 814	**13 648**
Energy services	159	160	151	112	66	75	**723**
Exploration work commitments	-	20	-	64	1	454	**539**
Other	648	185	108	83	62	339	**1 425**
	1 957	1 575	1 470	1 387	1 264	8 682	**16 335**

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 and Assets

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 or assets 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 24), 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.

Contingent assets are only disclosed when the inflow of economic benefits is probable. When the economic benefit becomes virtually certain, the asset is no longer contingent and is recognized in the consolidated financial statements.

(c) Guarantees

At December 31, 2021, the company has provided loan guarantees to certain retail licensees and wholesale marketers. Suncor's maximum potential amount payable under these loan guarantees is $134 million.

The company has also agreed to indemnify holders of all notes and debentures and the company's credit facility lenders (see note 21) 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, 2021, the probability is remote that these guarantee commitments will impact the company.

33. SALE OF GOLDEN EAGLE AREA DEVELOPMENT

During the fourth quarter of 2021, the company completed the sale of its 26.69% working interest in the Golden Eagle Area Development for gross proceeds of US$250 million net of closing adjustments and other closing costs, resulting in a gain on sale of $227 million ($227 million after-tax). In addition, contingent consideration of up to US$ 50 million is receivable in the second half of 2023, if between July 2021 and June 2023 the Dated Brent average crude price equals or exceeds US$55/bbl, upon which US$25 million is receivable; or if the Dated Brent average crude price equals or exceeds US$65/bbl, upon which US$50 million is receivable.

The company completed the sale on October 22, 2021 with an effective date of January 1, 2021. The Golden Eagle Area Development is reported within the Exploration and Production segment.

Exhibit 99.3

MANAGEMENT'S DISCUSSION AND ANALYSIS

February 23, 2022

This Management's Discussion and Analysis (MD&A) should be read in conjunction with Suncor's December 31, 2021 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 23, 2022 (the 2021 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 on our website at 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.

Suncor Energy Inc. has numerous direct and indirect subsidiaries, partnerships and joint arrangements (collectively, affiliates), which own and operate assets and conduct activities in different jurisdictions. The terms ''we'', ''our'', ''Suncor'', or ''the company'' are used herein for simplicity of communication and only mean there is an affiliation with Suncor Energy Inc., without necessarily identifying the specific nature of the affiliation. The use of such terms in any statement herein does not mean they apply to Suncor Energy Inc. or any particular affiliate, and does not waive the corporate separateness of any affiliate. For further clarity, Suncor Energy Inc. does not directly operate or own assets in the U.S. 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).

All financial information is reported in Canadian dollars, unless otherwise noted. Production volumes are presented on a working-interest basis, before royalties, except for production volumes from the company's Libya operations, which are on an economic basis.

Non-GAAP Financial Measures

Certain financial measures in this MD&A – namely adjusted operating earnings (loss), adjusted funds from (used in) operations, metrics contained in return on capital employed (ROCE) and ROCE excluding impairments, price realizations, Oil Sands operations cash operating costs, Fort Hills cash operating costs, Syncrude cash operating costs, refining and marketing margin, refining operating expense, free funds flow, discretionary free funds flow (deficit), net debt, total debt, and last-in, first-out (LIFO) inventory valuation methodology and related per share or per barrel amounts or metrics that contain such measures – are not prescribed by generally accepted accounting principles (GAAP). Adjusted 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, ROCE excluding impairments, price realizations, adjusted funds from (used in) operations, free funds flow, discretionary free funds flow (deficit), net debt, total debt, refining and marketing margin, and refining operating expense 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.

Beginning in the fourth quarter of 2021, the company changed the label of operating earnings (loss) and funds from (used in) operations to adjusted operating earnings (loss) and adjusted funds from (used in) operations, respectively, to better distinguish the non-GAAP financial measures from the comparable GAAP measures and better reflect the purpose of the measures. The composition of the measures remains unchanged and therefore no prior periods were restated.

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.

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. Readers of this information are cautioned that actual results may differ materially from those expressed or implied by forward-looking information contained herein. Refer to the Advisories – Forward-Looking Information section of this MD&A for information on the material risk factors and assumptions underlying the forward-looking information contained herein.

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1. FINANCIAL AND OPERATING SUMMARY

Financial Summary

Year ended December 31 ($ millions, except per share amounts)	2021	2020	2019
Gross revenues	**41 133**	24 900	39 866
Royalties	**(2 001)**	(238)	(1 522)
Operating revenues, net of royalties	**39 132**	24 662	38 344
Net earnings (loss)	**4 119**	(4 319)	2 899
per common share(1)	**2.77**	(2.83)	1.86
Adjusted operating earnings (loss)(2)(3)(4)	**3 805**	(2 213)	4 418
per common share(5)	**2.56**	(1.45)	2.83
Adjusted funds from operations(2)(3)	**10 257**	3 876	10 818
per common share(5)	**6.89**	2.54	6.94
Cash flow provided by operating activities	**11 764**	2 675	10 421
per common share(5)	**7.91**	1.75	6.69
Dividends paid on common shares	**1 550**	1 670	2 614
per common share(5)	**1.05**	1.10	1.68
Weighted average number of common shares in millions – basic	**1 488**	1 526	1 559
Weighted average number of common shares in millions – diluted	**1 489**	1 526	1 561
ROCE(2) (%)	**8.6**	(6.9)	4.9
ROCE excluding impairments and impairment reversals(2)(6) (%)	**8.2**	(2.9)	10.0
Capital expenditures(7)	**4 411**	3 806	5 436
Asset sustainment and maintenance	**3 057**	2 388	3 227
Economic investment	**1 354**	1 418	2 209
Discretionary free funds flow (deficit)(2)	**5 590**	(228)	4 914
Balance sheet (at December 31)			
Total assets	**83 739**	84 616	89 435
Net debt(2)	**16 149**	19 814	16 010
Total long-term liabilities(8)	**36 726**	38 310	36 856

(1) Represented on a basic and diluted per share basis.
(2) Non-GAAP financial measures or contains non-GAAP financial measures. See the Advisories – Non-GAAP Financial Measures section of this MD&A.
(3) Beginning in the fourth quarter of 2021, the company revised the label of operating earnings (loss) and funds from (used in) operations to adjusted operating earnings (loss) and adjusted funds from (used in) operations, respectively, to better distinguish the non-GAAP financial measures from the comparable GAAP measures and better reflect the purpose of the measures. The composition of the measures remains unchanged and therefore no prior periods were restated.
(4) Beginning in 2021, the company revised its calculation of adjusted operating earnings (loss), a non-GAAP financial measure, to exclude unrealized (gains) losses on derivative financial instruments that are recorded at fair value in other income (loss) to better align the earnings impact of the activity with the underlying items being risk-managed. Prior period comparatives have been restated to reflect this change.
(5) Represented on a basic per share basis.
(6) ROCE excluding impairments and impairment reversals would have been 8.2% in 2019, excluding the impacts of the $1.116 billion deferred tax recovery for the Alberta corporate income tax rate change in the second quarter of 2019.
(7) Excludes capitalized interest of $144 million in 2021, $120 million in 2020 and $122 million in 2019.
(8) Includes long-term debt, long-term lease liabilities, other long-term liabilities, provisions and deferred income taxes.

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Operating Summary

Year ended December 31	2021	2020	2019
Production volumes[1]			
Oil Sands - Upgraded - net SCO and diesel (mbbls/d)	**468.6**	466.2	485.6
Oil Sands - Non-upgraded bitumen (mbbls/d)	**175.6**	127.2	184.8
Exploration and Production (mboe/d)	**87.5**	101.7	106.8
Total	**731.7**	695.1	777.2
Average price realizations[2][3][4] ($/boe)			
SCO and diesel	**77.73**	43.83	70.68
Non-upgraded bitumen[2]	**53.80**	22.37	45.71
Oil Sands crude sales basket (all products)	**70.96**	39.29	63.70
Exploration and Production Canada – Crude oil and natural gas liquids ($/bbl)	**84.70**	49.69	84.86
Exploration and Production International[5] ($/boe)	**82.16**	50.28	81.22
Refinery crude oil processed (mbbls/d)	**415.5**	407.0	438.9
Refinery utilization[6] (%)			
Eastern North America	**91**	91	92
Western North America	**87**	86	98
Total	**89**	88	95
Refining and marketing gross margin - FIFO [3][7] ($/bbl)	**36.85**	25.30	40.45
Refining and marketing gross margin - LIFO [3][7] ($/bbl)	**30.90**	28.65	36.80

(1) Beginning in 2020, the company revised the presentation of its production volumes to aggregate production from each asset into the categories of "Upgraded production" and "Non-upgraded bitumen production" to better reflect the integration among the company's assets with no impact to overall production volumes. Comparative periods have been updated to reflect this change.

(2) Beginning in 2020, the company revised the presentation of its Oil Sands price realizations to aggregate price realizations from each asset into the categories of "SCO and diesel" and "Non-upgraded bitumen" to better reflect the integration among the company's assets with no impact to overall price realizations. Comparative periods have been updated to reflect this change. Beginning in 2020, the company revised its "Non-upgraded bitumen" price realization to include midstream activities employed to optimize its logistics capacity and more accurately reflect the performance of the product stream. Comparative periods have been restated to reflect this change.

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

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

(5) Exploration and Production International price realizations include the company's U.K. and Norway assets and exclude Libya for all periods presented.

(6) Refinery utilization is the amount of crude oil run through crude distillation units, expressed as a percentage of the nameplate capacity of these units. The Edmonton refinery crude processing capacity has increased to 146,000 bbls/d in 2021 from 142,000 bbls/d in 2020.

(7) Beginning in 2020, refining and marketing gross margins have been revised to better reflect the refining, product supply and rack forward businesses. Prior periods have been restated to reflect this change.

Segment Summary

Year ended December 31 ($ millions)	2021	2020	2019
Net earnings (loss)			
Oil Sands	**2 147**	(3 796)	(427)
Exploration and Production	**1 285**	(832)	1 005
Refining and Marketing	**2 178**	866	3 000
Corporate and Eliminations	**(1 491)**	(557)	(679)
Total	**4 119**	(4 319)	2 899
Adjusted operating earnings (loss) (1)(2)			
Oil Sands	**2 151**	(2 265)	1 672
Exploration and Production	**890**	13	1 141
Refining and Marketing	**2 170**	882	2 922
Corporate and Eliminations	**(1 406)**	(843)	(1 317)
Total	**3 805**	(2 213)	4 418
Adjusted funds from (used in) operations (1)			
Oil Sands	**6 846**	1 986	6 061
Exploration and Production	**1 478**	1 054	2 143
Refining and Marketing	**3 255**	1 708	3 863
Corporate and Eliminations	**(1 322)**	(872)	(1 249)
Total adjusted funds from operations	**10 257**	3 876	10 818
Change in non-cash working capital	**1 507**	(1 201)	(397)
Cash flow provided by operating activities	**11 764**	2 675	10 421

(1) Non-GAAP financial measures. See the Advisories – Non-GAAP Financial Measures section of this MD&A.
(2) Beginning in 2021, the company revised its calculation of adjusted operating earnings (loss), a non-GAAP financial measure, to exclude unrealized (gains) losses on derivative financial instruments that are recorded at fair value in other income (loss) to better align the earnings impact of the activity with the underlying items being risk-managed. Prior period comparatives have been restated to reflect this change.

2. SUNCOR OVERVIEW

Suncor is an integrated energy company headquartered in Calgary, Alberta, Canada. Suncor's operations include oil sands development, production and upgrading; offshore oil and gas; petroleum refining in Canada and the U.S.; and the company's Petro-Canada retail and wholesale distribution networks (including Canada's Electric Highway™, a coast-to-coast network of fast-charging electric vehicle stations). Suncor is developing petroleum resources while advancing the transition to a low-emissions future through investment in power, renewable fuels and hydrogen. Suncor also conducts energy trading activities focused principally on the marketing and trading of crude oil, natural gas, byproducts, refined products and power. Suncor has been recognized for its performance and transparent reporting on the Dow Jones Sustainability index, FTSE4Good and CDP. Suncor is also listed on the UN Global Compact 100 stock index. Suncor's common shares (symbol: SU) are listed on the Toronto Stock Exchange (TSX) and the New York Stock Exchange (NYSE).

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 operational excellence, underpinned by safety above all else, capital discipline through investments in high-value projects, and our commitment to environmental stewardship and sustainability. We believe that our commitment to capital discipline, our balance sheet strength and financial health provides the foundation for our capital allocation framework, supporting long-term value creation and increasing returns to shareholders. We believe that Suncor is well positioned to execute on these priorities due to the company's competitive advantages: financial strength, an industry-leading long-life, low-decline oil sands reserves base, an offshore business that provides geographically diversified cash flow, a highly efficient, tightly integrated downstream business supported by competitive sales channels, 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 highly economic projects and initiatives that are synergistic with our core capabilities and are expected to create long-term value for the company through 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 digital mine optimization, innovative tailings technology advancements and the replacement

of the coke-fired boilers at Oil Sands Base with a cogeneration facility. Further structural cost savings are being realized through supply chain optimization initiatives and investments in technology for our marketing and trading business and core business systems, aimed at improving operational efficiencies, structurally lowering costs and improving margin capture.

- **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 the regional strength of the company's Oil Sands assets and the integration with its midstream and refining assets. Our broad asset base and operational flexibility allows us to optimize the production of higher-value SCO in the upstream, while our extensive logistics assets and sales channels, enhanced by our trading and marketing expertise, drives additional value as equity barrels move down the value chain. Through this midstream and marketing network and our geographical diversity, the company is able to maximize crude production and refinery utilization by securing sales outlets while receiving global-based pricing for the majority of its production.

- **Maximize value and structurally lower costs through operational excellence and reliability** – Suncor aims to get the most out of its assets through a focus on operational excellence, which means operating in a way that is safe, reliable, cost-efficient and environmentally responsible, while continuing to practice capital discipline. We believe that focusing on investments that generate structural reductions to our capital requirements, with a continued focus on improved productivity and reliability, will drive down overall cost structures and sustainment capital requirements and are expected to help us achieve maximum value from our operations. Suncor assuming operatorship of the Syncrude asset on September 30, 2021, was a critical step towards structural cost reductions by driving greater integration, efficiencies and competitiveness across the company's Oil Sands assets. The interconnecting pipelines between Oil Sands Base and Syncrude add to the company's regional oil sands advantage, providing operational flexibility and supporting stronger reliability.

- **Be an industry leader in sustainable development and the global energy expansion** – Suncor's integrated approach to sustainability includes leadership and industry collaboration in environmental performance, enhanced social responsibility and safety, underpinned by strong governance and our commitment to creating value for our stakeholders. Our objective is to be a net-zero greenhouse gas (GHG) emissions company by 2050 and we have set ambitious near-term goals to reduce emissions across our value chain. We aim to substantially contribute to society's net-zero goals by reducing emissions across our base business, growing our low-emissions energy business, and working with others to reduce emissions. We are expanding our low-emissions energy business by pursuing investments that are technologically mature, economically viable and synergistic with our existing integrated value chain. Our investments in the energy expansion will complement our existing core capabilities; increasing low carbon power generation, expanding into clean hydrogen production, and growing our existing renewable liquid fuels business.

- **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.

2021 Highlights

Suncor exceeded its return to shareholder targets for the year, repurchasing its common shares at the highest annual rate in the company's history, and increasing the dividend by 100% in the fourth quarter, returning a total of $3.9 billion to shareholders.

- Suncor paid $1.6 billion of dividends in 2021, demonstrating management's confidence in the company's ability to generate sustainable and increasing cash flows and its commitment to increasing shareholder returns. The company increased its dividend per share by 100% in the fourth quarter, reinstating the quarterly dividend to $0.42 per share, returning it to 2019 levels.

- In 2021, the company accelerated its share repurchase target, repurchasing the company's common shares at the highest annual rate in the company's history. In 2021, since the start of the company's normal course issuer bid program (NCIB) in February 2021, the company repurchased $2.3 billion in common shares, representing approximately 84 million of its common shares at an average price of $27.45 per common share, or the equivalent of 5.5% of Suncor's common shares as at January 31, 2021.

- Subsequent to the end of the year, the company repurchased an additional 0.5% of its common shares up to February 7, 2022, and renewed its NCIB, beginning February 8, 2022, and ending February 7, 2023, for the repurchase of up to approximately 5% of Suncor's issued and outstanding common shares as at January 31, 2022.

In 2021, Suncor accelerated its net debt(1) reduction targets, reducing debt at the highest annual pace in the company's history, returning to 2019 levels of net debt.

- In 2021, Suncor executed on its net debt reduction targets, reducing debt at the highest-ever annual pace, resulting in a reduction of net debt by $3.7 billion to $16.1 billion, returning to 2019 net debt levels. The company continues to reduce its debt to achieve its 2025 and 2030 targets, and subsequent to the end of the year, completed an early redemption of its outstanding US$182 million 4.50% notes, originally scheduled to mature in the second quarter of 2022.

- In 2021, demonstrating management's confidence in the company's ability to generate cash flows, the company cancelled $2.8 billion in bi-lateral credit facilities that were no longer required, as they were entered into in March and April of 2020 to ensure access to adequate financial resources in connection with the COVID-19 pandemic.

In 2021, Suncor generated $10.3 billion of adjusted funds from operations(1), the second-highest in the company's history, reflecting the ability of its integrated business to deliver strong results. Cash flow provided by operating activities in 2021 was the highest in the company's history.

- In 2021, Suncor generated $10.257 billion in adjusted funds from operations, or $6.89 per common share, compared to $3.876 billion, or $2.54 per common share, in the prior year. Cash flow provided by operating activities, which includes changes in non-cash working capital, was $11.764 billion, or $7.91 per common share, in 2021, compared to $2.675 billion, or $1.75 per common share, in the prior year. The increased cash flows were a result of the improved business environment and higher crude oil production and refinery throughput in the current year, despite the largest annual maintenance program in the company's history being successfully executed during the year.

- Suncor's adjusted operating earnings(1) in 2021 were $3.805 billion, compared to an adjusted operating loss of $2.213 billion in the prior year. Net earnings were $4.119 billion in 2021, compared to a net loss of $4.319 billion in the prior year.

Oil Sands delivered record annual adjusted funds from operations of over $6.8 billion, including record In Situ production, maximizing value through strong reliability and leveraging the strength of its integrated operations, while successfully executing the largest annual maintenance program in the company's history.

- Oil Sands delivered record annual adjusted funds from operations of $6.846 billion, driven by improved crude oil prices and strong reliability across its assets in 2021, compared to $1.986 billion in the prior year.

- In 2021, Suncor delivered total Oil Sands production of 644,200 bbls/d, the second highest Oil Sands production in the company's history, driven by record performance from the company's In Situ assets, including at Firebag, following an increase to the nameplate capacity of the facility in the prior year.

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

- SCO production was 468,600 bbls/d in 2021, the second-highest in the company's history, driven by combined upgrader utilization of 87% despite the impacts of significant turnaround maintenance during the year, demonstrating the value of the company's asset integration and flexibility and reflecting a continued focus on maximizing the value of its barrels. Non-upgraded bitumen production was 175,600 bbls/d in 2021, an increase of 38% compared to the prior year, with the increase in non-upgraded bitumen production to market further supported by strong mining performance at Oil Sands Base, which resulted in less Firebag volumes utilized at the Upgrader and overall higher Oil Sands operations production volumes.

- Fort Hills resumed two-train operations late in the fourth quarter of 2021. The company is on track to operate the Fort Hills asset at average utilization rates of 90% throughout 2022.

- In 2021, the company focused on the safety and reliability of its operations by successfully executing the largest annual maintenance program in the company's history across its asset base, including the significant five-year planned turnaround at Oil Sands Base plant Upgrader 2 and significant turnaround activities at Syncrude.

The company made meaningful progress towards driving synergies between its regional Oil Sands assets, while furthering its sustainability goals.

- On September 30, 2021, Suncor assumed the role of operator of the Syncrude asset, a critical step towards driving greater integration, efficiencies and competitiveness across all Suncor-operated assets in the region, further strengthening the company's regional oil sands advantage. The joint venture owners expect that Suncor assuming operatorship will capture increased value for the owners through improved operational performance, efficiency and competitiveness.

- During the year, Suncor, together with eight Indigenous communities, announced the formation of Astisiy Limited Partnership (Astisiy), which acquired a 15% equity interest in the Northern Courier Pipeline. The Northern Courier Pipeline, which connects the Fort Hills asset to Suncor's East Tank Farm, is now operated by Suncor and is expected to provide the eight Indigenous communities with reliable income for decades.

Exploration & Production (E&P) reinforces its focus on capital discipline by targeting low-cost projects that deliver significant returns, cash flow and long-term value.

- In 2021, Suncor and the co-owners of the Terra Nova project finalized an agreement to restructure the project ownership and move forward with the Asset Life Extension (ALE) Project, which is expected to extend production life by approximately 10 years. As a result of the agreement, Suncor increased its ownership in the project by approximately 10% to 48%. The Terra Nova Floating, Production, Storage and Offloading facility is dry-docked in Spain undergoing maintenance work and is expected to sail back to Canada and return to operations before the end of 2022.

- Buzzard Phase 2, which will extend production life of the existing Buzzard field, achieved first oil in the fourth quarter of 2021. Buzzard Phase 2 is expected to reach its peak production in 2022, adding approximately 12,000 boe/d gross (approximately 3,500 boe/d net to Suncor) to existing Buzzard production.

- The company completed the sale of its 26.69% working interest in the Golden Eagle Area Development for gross proceeds of US$250 million net of closing adjustments and other closing costs, in addition to future contingent consideration of up to US$50 million. The effective date of the sale was January 1, 2021. The sale reinforces Suncor's continued focus on capital discipline and enables the company to allocate resources to core assets and maximize shareholder returns.

Suncor's Refining and Marketing (R&M) segment achieved refinery utilization of 89% in 2021, consistently outperforming the Canadian refining industry average, despite turnarounds being completed across all of its refineries and continued weakness in Canadian demand.

- Suncor leveraged its refinery product mix, midstream logistics flexibility, strong domestic sales network including integration with its retail network, export capabilities and storage capacity to deliver refinery crude throughput of 415,500 bbls/d in 2021, and industry-leading utilization rates of 89%, compared to 407,000 bbls/d and 88% in the prior year.

- The company's Canadian refineries outperformed the Canadian refining industry average by over 12% (1) during the year, despite turnarounds being completed across all of the company's refineries.

- R&M delivered $3.255 billion and $2.170 billion in adjusted funds from operations and adjusted operating earnings in 2021, respectively, compared to $1.708 billion and $882 million, respectively, in the prior year. In 2021, the impact of the FIFO method of inventory valuation, relative to an estimated LIFO method, had a positive impact to adjusted operating earnings and adjusted funds from operations of $795 million after-tax, compared to a negative after-tax impact of $384 million in 2020.

The company announced its strategic objective to be a net-zero GHG emissions company by 2050 and advanced its goal with strategic investments in new technologies that are synergistic with its existing integrated energy value chain.

- The company announced its new strategic objective to become a net-zero GHG emissions company by 2050 and to substantially contribute to society's net-zero ambitions. The company set near-term absolute emissions reduction goals to align with its objective to reach net-zero emissions and plans to meet its goals by reducing its base business emissions, investing in low-emissions ventures and technologies and taking actions that reduce others' emissions.

- In 2021, Suncor, together with industry partners representing over 90% of Canada's oil sands production, announced the Oil Sands Pathways to Net Zero alliance, whose initiative is aimed at working collectively with the federal and Alberta governments to achieve net-zero GHG emissions from oil sands operations by 2050.

- During 2021, the company increased its investments in clean technology, including an equity investment in Svante Inc., a Canadian carbon capture company that plans to develop technology to capture CO_2 from industrial processes at reduced costs, and increased its investment in the Varennes Carbon Recycling facility.

(1) Source: Canada Energy Regulator – https://www.cer-rec.gc.ca/en/data-analysis/energy-commodities/crude-oil-petroleum-products/statistics/weekly-crude-run-summary-data/index.html.

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3. FINANCIAL INFORMATION

Net Earnings (Loss)

Suncor's net earnings in 2021 were $4.119 billion, compared to a net loss of $4.319 billion in 2020. Net earnings (loss) were impacted by the same factors that influenced adjusted operating earnings (loss), which are described below. Other items affecting net earnings (loss) in 2021 and 2020 included:

- An unrealized foreign exchange gain on the revaluation of U.S. dollar denominated debt of $113 million ($101 million after-tax) recorded in financing expenses in 2021, compared to a gain of $312 million ($286 million after-tax) in 2020.
- In 2021, the company recorded a non-cash impairment reversal of $221 million ($168 million after-tax) against its share of the Terra Nova assets, in the E&P segment, as a result of the Terra Nova ALE Project moving forward and the benefit of royalty and financial support from the Government of Newfoundland and Labrador.
- A restructuring charge of $168 million ($126 million after-tax) in 2021 related to workforce reductions, recorded in operating, selling and general expenses in the Corporate and Eliminations segment.
- A loss of $80 million ($60 million after-tax) in 2021 for early repayment of long-term debt, recorded in financing expenses in the Corporate and Eliminations segment.
- A gain of $227 million ($227 million after-tax) in 2021 on the sale of the company's interest in the Golden Eagle Area Development, in the E&P segment.
- In 2020, the company recorded non-cash impairment charges of $1.821 billion ($1.376 billion after-tax) on its share of the Fort Hills assets, in the Oil Sands segment, and $1.119 billion ($845 million after-tax) against its share of the White Rose and Terra Nova assets, in the E&P segment, due to a decline in forecasted crude oil prices in 2020 as a result of decreased global demand due to the impacts of the COVID-19 pandemic, the high degree of uncertainty surrounding the future of the West White Rose Project and changes to their respective capital, operating and production plans.
- In 2020, the company recorded a provision to transportation expense for $186 million ($142 million after-tax) related to the Keystone XL pipeline project in the Oil Sands segment.

Adjusted Operating Earnings (Loss)

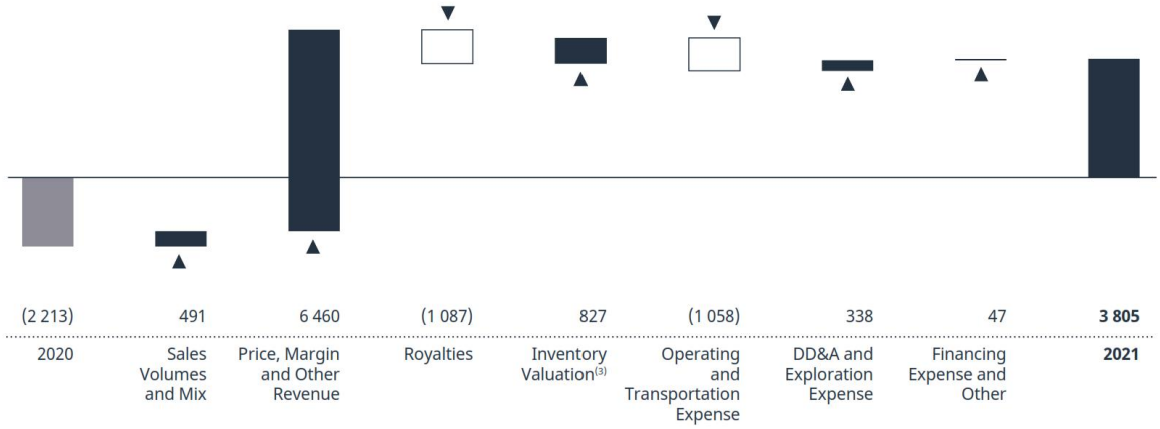
Consolidated Adjusted Operating Earnings (Loss) Reconciliation (1)(2)

Year ended December 31 ($ millions)	2021	2020	2019
Net earnings (loss)	**4 119**	(4 319)	2 899
Unrealized foreign exchange gain on U.S. dollar denominated debt	**(101)**	(286)	(590)
Unrealized (gain) loss on risk management activities (2)	**(4)**	29	60
Asset (reversal) impairments (3)	**(168)**	2 221	3 352
Restructuring charge	**126**	—	—
Loss on early repayment of long-term debt	**60**	—	—
Gain on significant disposals (4)	**(227)**	—	(187)
Provision for pipeline project	**—**	142	—
Impact of income tax adjustments on deferred income taxes (5)	**—**	—	(1 116)
Adjusted operating earnings (loss) (1)(2)	**3 805**	(2 213)	4 418

(1) Non-GAAP financial measure. See the Advisories – Non-GAAP Financial Measures section of this MD&A.
(2) Beginning in 2021, the company revised its calculation of adjusted operating earnings (loss), a non-GAAP financial measure, to exclude unrealized (gains) losses on derivative financial instruments that are recorded at fair value in other income (loss) to better align the earnings impact of the activity with the underlying items being risk-managed. Prior period comparatives have been restated to reflect this change.
(3) During 2019, the company recorded non-cash impairment charges of $3.716 billion ($2.803 billion after-tax) on its share of the Fort Hills assets, in the Oil Sands segment, due to a decline in forecasted heavy crude oil prices and $521 million ($393 million after-tax) against White Rose, in the E&P segment, due to increased capital cost estimates at the West White Rose Project.
(4) In 2019, Suncor sold its 37% interest in Canbriam Energy Inc., in the E&P segment, for proceeds of $151 million ($139 million after-tax). 2019 also included a gain of $65 million ($48 million after-tax) in the E&P segment related to the sale of certain non-core assets.
(5) 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%.

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Bridge Analysis of Adjusted Operating (Loss) Earnings ($ millions)[1][2]



(1) For an explanation of the construction of this bridge analysis, see the Advisories – Non-GAAP Financial Measures section of this MD&A.
(2) Beginning in 2021, the company revised its calculation of adjusted operating earnings (loss), a non-GAAP financial measure, to exclude unrealized (gains) losses on derivative financial instruments that are recorded at fair value in other income (loss) to better align the earnings impact of the activity with the underlying items being risk-managed. Prior period comparatives have been restated to reflect this change.
(3) The bridge factor for Inventory Valuation is comprised of changes in the first-in, first-out (FIFO) inventory valuation and short-term commodity risk management activities reported in the R&M segment, and changes in the intersegment elimination of profit reported in the Corporate and Eliminations segment.

Suncor's consolidated adjusted operating earnings increased to $3.805 billion in 2021, compared to an adjusted operating loss of $2.213 billion in the prior year. In 2021, crude oil and refined production realizations increased significantly compared to the prior year, which was significantly impacted by the COVID-19 pandemic and an increase in OPEC+ crude supply. The improving business environment in 2021 also resulted in a net favourable inventory valuation change on crude feedstock costs. Adjusted operating earnings in 2021 were also favourably impacted by higher overall crude production and refinery throughput.

These factors were partially offset by an increase in royalties, primarily associated with higher crude price realizations, and increased operating and transportation expenses. The prior year adjusted operating loss was negatively impacted by the significant decline in transportation fuel demand and a net inventory valuation loss, partially offset by cost reductions in response to the COVID-19 pandemic.

Adjusted Funds from Operations and Cash Flow Provided by Operating Activities

Adjusted funds from operations for 2021 were $10.257 billion, compared to $3.876 billion in 2020, and were impacted by the same factors as adjusted operating earnings (loss) described above.

Cash flow provided by operating activities, which includes changes in non-cash working capital, was $11.764 billion in 2021, compared to $2.675 billion in 2020, reflecting a source of cash in working capital in the current year, compared to a use of cash in the prior year. The source of cash in 2021 was primarily due to a net increase in taxes payable related to the company's 2021 income tax expense, which is payable in early 2022, receipt of the company's 2020 federal income tax refund, and an increase in accounts payable and accrued liabilities, partially offset by an increase in accounts receivable related to an increase in crude oil price realizations during the year.

Results for 2020 Compared with 2019

Suncor's net loss in 2020 was $4.319 billion, compared to net earnings of $2.899 billion in 2019. Net (loss) earnings were impacted by the same factors impacting adjusted operating (loss) earnings described below, as well as the net earnings adjustments impacting 2020 and 2019, which are described in detail above.

Suncor's consolidated adjusted operating loss in 2020 was $2.213 billion, compared to adjusted operating earnings of $4.418 billion in 2019. In 2020, crude oil and refined product realizations decreased significantly, with 2020 crude oil and crack spread benchmarks declining by more than 30% compared to the prior year due to the impacts of the COVID-19 pandemic and OPEC+ supply issues. The decline in consumer demand for refined products resulted in lower crude oil demand and lower overall upstream production volumes and refinery crude throughput as the company managed its operations to meet demand levels. 2020 results were also impacted by a FIFO inventory valuation loss on the decline in value of refinery feedstock. Adjusted operating losses were minimized by the decrease in costs associated with lower production as well as cost-reduction initiatives executed in 2020. Adjusted operating earnings in 2019 included insurance proceeds related to the company's assets in Libya.

Adjusted funds from operations for 2020 were $3.876 billion, compared to $10.818 billion in 2019, and were impacted by the same factors as adjusted operating (loss) earnings described above.

Cash flow provided by operating activities, which includes changes in non-cash working capital, was $2.675 billion in 2020, compared to $10.421 billion in 2019, reflecting a larger use of cash in working capital compared to 2019, which was primarily due to a decrease in accounts payable balances associated with lower operating costs and an increase in income tax receivable balances resulting from the carry-back of tax losses, which was received in 2021.

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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	**2021**	2020	2019
WTI crude oil at Cushing (US$/bbl)	**67.95**	39.40	57.05
Dated Brent Crude (US$/bbl)	**70.75**	41.65	64.30
Dated Brent/Maya crude oil FOB price differential (US$/bbl)	**6.85**	6.35	6.45
MSW at Edmonton (Cdn$/bbl)	**80.30**	45.60	69.20
WCS at Hardisty (US$/bbl)	**54.90**	26.85	44.25
Light/heavy differential for WTI at Cushing less WCS at Hardisty (US$/bbl)	**(13.05)**	(12.55)	(12.80)
SYN-WTI differential (US$/bbl)	**(1.65)**	(3.15)	(0.60)
Condensate at Edmonton (US$/bbl)	**68.25**	37.15	52.85
Natural gas (Alberta spot) at AECO (Cdn$/mcf)	**3.65**	2.25	1.75
Alberta Power Pool Price (Cdn$/MWh)	**101.95**	46.70	54.90
New York Harbor 2-1-1 crack (1) (US$/bbl)	**19.40**	11.75	19.90
Chicago 2-1-1 crack (1) (US$/bbl)	**17.75**	8.05	17.05
Portland 2-1-1 crack (1) (US$/bbl)	**23.15**	14.05	24.45
Gulf Coast 2-1-1 crack (1) (US$/bbl)	**18.00**	9.90	19.15
U.S. Renewable Volume Obligation (US$/bbl)	**6.77**	2.48	1.20
Exchange rate (US$/Cdn$)	**0.80**	0.75	0.75
Exchange rate (end of period) (US$/Cdn$)	**0.79**	0.78	0.77

(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 crack spreads presented here generally approximate the regions into which the company sells refined products through retail and wholesale channels.

In 2021, crude oil and crack spread benchmarks improved compared to 2020, which was significantly impacted by an unprecedented decline in transportation fuel demand due to the impacts of the COVID-19 pandemic.

Suncor's sweet SCO price realizations are influenced primarily by the price of WTI at Cushing and by the supply and demand for sweet SCO from Western Canada. Sweet SCO price realizations were favourably impacted in 2021 and reflected an increase in WTI at Cushing, which averaged US$67.95/bbl compared to US$39.40/bbl in the prior year. Suncor also produces sour SCO, the price of which is 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 increased to $80.30/bbl in 2021 compared to $45.60/bbl in 2020, and prices for WCS at Hardisty increased to US$54.90/bbl in 2021, from US$26.85/bbl in 2020.

Bitumen production that Suncor does not upgrade is blended with diluent or SCO to facilitate delivery through pipeline systems. Net bitumen price realizations are, therefore, influenced by both prices for Canadian heavy crude oil (WCS at Hardisty is a common reference), prices for diluent (Condensate at Edmonton) and SCO. Bitumen price realizations can also be affected by bitumen quality premiums and discounts and spot sales, and the price differential between Hardisty, Alberta, and U.S. Gulf Coast benchmarks.

The company leverages the expertise of its marketing and logistics business to optimize midstream capacity to the U.S. Gulf Coast and this is reflected in bitumen and sour SCO price realizations. Bitumen prices were unfavourably impacted by the widening of heavy crude oil differentials in 2021 compared to 2020, but were higher on an absolute basis due to the increase in WTI prices.

Suncor's price realizations for production from E&P Canada and E&P International assets are influenced primarily by the price for Brent crude, which increased to US$70.75/bbl in 2021, compared to US$41.65/bbl in 2020.

Suncor's refining and marketing gross margins are primarily influenced by 2-1-1 benchmark crack spreads, which are industry indicators approximating the gross margin on a barrel of crude oil that is refined to produce gasoline and distillates. Market crack spreads are based on quoted near-month contracts for WTI and spot prices for gasoline and diesel and do not necessarily reflect the margins at a specific refinery. Suncor's realized refining and marketing gross margins are influenced by actual crude oil feedstock costs, refinery configuration, product mix and realized market prices unique to Suncor's refining and marketing business. In addition, the U.S. regulatory renewable blending obligations influence the benchmark cracks, which may increase their volatility, while the cost of regulatory compliance is not deducted in calculating the benchmark cracks.

Suncor has developed an indicative 5-2-2-1 index based on publicly available pricing data to more accurately reflect Suncor's realized refining and marketing gross margin. This internal index is a single value calculated based on a notional five barrels

of crude oil of varying grades refined to produce two barrels each of gasoline and distillate and one barrel of secondary product to approximate Suncor's unique set of refinery configurations; overall crude slate and product mix; and the benefit of its location, quality and grade differentials, and marketing margins. The internal index is calculated by taking the product value of refined products less the crude value of refinery feedstock excluding the impact of FIFO inventory accounting methodology. The product value incorporates the New York Harbor 2-1-1 crack, Chicago 2-1-1 crack, WTI benchmarks and seasonal factors. The seasonal factor applies an incremental US$6.50/bbl in the first and fourth quarters and US$5.00/bbl in the second and third quarters and reflects the location, quality and grade differentials for refined products sold in the company's core markets during the winter and summer months, respectively. The crude value incorporates the SYN, WCS and WTI benchmarks.

Crack spreads are based on current crude feedstock prices, whereas actual earnings are accounted for on a FIFO basis in accordance with IFRS where a delay exists between the time that feedstock is purchased and when it is processed and when products are 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. The company's realized refining and marketing gross margins are also presented on a LIFO basis, which is consistent with how industry benchmarks and the Suncor 5-2-2-1 index are calculated and with how management evaluates performance.

In 2021, the New York Harbor 2-1-1 and Chicago 2-1-1 benchmark crack spreads increased compared to 2020 due to increased demand for transportation fuels and to compensate for increased costs associated with renewable blending regulatory obligations. The Suncor 5-2-2-1 index was US$26.55/bbl in 2021 compared to US$19.95/bbl in 2020, primarily related to the increase in benchmark crack spreads.

The cost of 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 $3.65/mcf in 2021, from $2.25/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 $101.95/MWh in 2021 from $46.70/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, while 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 2021, the Canadian dollar strengthened in relation to the U.S. dollar as the average exchange rate increased to US$0.80 per one Canadian dollar from US$0.75 per one Canadian dollar in 2020. The increase in the Canadian dollar relative to the U.S. dollar had a negative impact on price realizations for the company in 2021 when compared to 2020.

Conversely, some of Suncor's assets and liabilities, notably approximately 60% of the company's debt, are denominated in U.S. dollars and translated to Suncor's reporting currency (Canadian dollars) at each balance sheet date. A decrease in the value of the Canadian dollar, relative to the U.S. dollar, from the previous balance sheet date increases the amount of Canadian dollars required to settle U.S. dollar denominated obligations, while an increase in the value of the Canadian dollar, relative to the U.S. dollar, 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 2021 net earnings and adjusted funds from operations(3) if the listed changes had occurred.

(Estimated change, in $ millions)	Impact on 2021 Net Earnings	Impact on 2021 Adjusted Funds from Operations (3)
Crude oil +US$1.00/bbl	200	200
Natural gas +Cdn$0.10/mcf(4)	(25)	(25)
WTI – narrowing light/heavy differential +US$1.00/bbl	15	15
2-1-1 crack spreads +US$1.00/bbl	140	140
Foreign exchange +$0.01 US$/Cdn$ related to operating activities (5)	(180)	(180)
Foreign exchange on U.S. dollar denominated debt +$0.01 US$/Cdn$	150	—

(1) Each line item in this table shows the effects of a change in that variable only, with other variables being held consistent.
(2) Changes for a variable imply that all such similar variables are impacted, such that Suncor's average price realizations increase uniformly. For instance, "Crude oil +US$1.00/bbl" implies that price realizations influenced by WTI, Brent, SCO, WCS, par crude at Edmonton and condensate all increase by US$1.00/bbl.
(3) Non-GAAP financial measure. See the Advisories – Non-GAAP Financial Measures section of this MD&A.
(4) The company's exposure to natural gas costs is partially mitigated by increased revenue from power sales, which is not included in the above sensitivity.
(5) Excludes the foreign exchange impact on U.S. dollar denominated debt.

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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, produces bitumen from mining and in situ operations. Bitumen is either upgraded into SCO for refinery feedstock and diesel fuel, or blended with diluent for refinery feedstock or direct sale to market through the company's midstream infrastructure and its marketing activities. The segment includes the marketing, supply, transportation and risk management of crude oil, natural gas, power and byproducts. 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 and the interconnecting pipelines between Suncor's Oil Sands Base operations and Syncrude.
    - **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 that may support future in situ production, including Meadow Creek (75%), Lewis (100%), OSLO (77.78%), Gregoire (100%), 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 the Fort Hills mining and extraction operation, 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 oil sands mining and upgrading operation, which the company operates. Suncor assumed the role of operator of the Syncrude joint operation o n September 30, 2021.

EXPLORATION AND PRODUCTION

Suncor's E&P segment consists of offshore operations off the east coast of Canada and in the North Sea, the Norwegian Sea and the Norwegian North Sea, and onshore assets in Libya and Syria. This segment also includes the marketing and risk management of crude oil and natural gas.

- **E&P Canada** operations include Suncor's 48% working interest in Terra Nova, which Suncor operates. Production at Terra Nova has been shut in since the fourth quarter of 2019. In the third quarter of 2021, a new ownership agreement was finalized that increased Suncor's working interest from 37.675% to 48%, and a decision was made to move forward with the ALE Project. The company is anticipating a safe and reliable return to operations before the end of 2022. Suncor also holds non-operated interests in Hibernia (20% in the base project and 19.485% in the Hibernia Southern Extension Unit), White Rose (27.5% in the base project and 26.125% in the extensions), and Hebron (21.034%). Suncor increased its non-operated interest in the Hibernia Southern Extension Unit from 19.19% in 2020 to 19.485% in 2021 through redetermination. In 2021, Suncor entered into a conditional agreement to increase its interest in the White Rose assets by 12.5% to approximately 40% on a go-forward basis, subject to a number of conditions including an economic restart decision by the operator on the West White Rose Project by mid-2022. In addition, the company holds interests in several exploration licences and significant discovery licences offshore Newfoundland and Labrador.
- **E&P International** operations include Suncor's non-operated interests in Buzzard (29.89%), Oda (30%), the Fenja Project (17.5%) and the Rosebank future development project (40%). In the fourth quarter of 2021, Suncor sold its 26.69% working interest in the Golden Eagle Area Development located in the U.K. sector of the North Sea. Buzzard 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. Production in Libya was steady in 2021, albeit at reduced rates. The timing of a return to normal operations in Libya remains uncertain due to continued political unrest. Suncor also owns, pursuant to a production sharing contract, 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, supply and risk management of refined products, crude oil, natural gas, power and byproducts. This segment also includes the trading of crude oil, refined products, natural gas and power.

- **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 mbbls/d refinery located in Montreal, Quebec, and an 85 mbbls/d refinery located in Sarnia, Ontario.
    - **Western North America** operations include a 146 mbbls/d refinery located in Edmonton, Alberta, and a 98 mbbls/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 customers primarily through a combination of company-owned Petro-Canada™ locations, branded-dealers in Canada and company-owned locations in the U.S. marketed under other international brands. This includes Canada's Electric Highway™, a coast-to-coast network of fast-charging electric vehicle stations. The company's marketing operations also sells refined petroleum products through a nationwide commercial road transportation network in Canada, and to other commercial and industrial customers, including other retail sellers, in Canada and the U.S.

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 Forty Mile Wind Power Project, which was restarted in early 2021 and is currently planned for completion in late 2022.
- **Corporate** activities include stewardship of Suncor's debt and borrowing costs, expenses not allocated to the company's businesses, and investments in clean technology, such as Suncor's investment in Enerkem Inc., LanzaJet, Inc., Svante Inc. and the Varennes Carbon Recycling facility.
- Intersegment revenues and expenses are removed from consolidated results in **Eliminations**. Intersegment activity includes the sale of product between the company's segments, primarily relating to crude refining feedstock sold from Oil Sands to Refining and Marketing.

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OIL SANDS

2021 Highlights

- Oil Sands delivered record annual adjusted funds from operations [1] of $6.846 billion, driven by improved crude oil prices and strong reliability across its assets in 2021, compared to $1.986 billion in the prior year.
- In 2021, Suncor delivered total Oil Sands production of 644,200 bbls/d, the second-highest Oil Sands production in the company's history, driven by record performance from the company's In Situ assets, including at Firebag, following an increase to the nameplate capacity of the facility in the prior year.
- SCO production was 468,600 bbls/d in 2021, the second highest in the company's history, driven by combined upgrader utilization of 87% despite the impacts of significant turnaround maintenance during the year, demonstrating the value of the company's asset integration and flexibility and reflecting a continued focus on maximizing the value of its barrels. Non-upgraded bitumen production was 175,600 bbls/d in 2021, an increase of 38% compared to the prior year, with the increase in non-upgraded bitumen production to market further supported by strong mining performance at Oil Sands Base, which resulted in less Firebag volumes utilized at the Upgrader and overall higher Oil Sands operations production volumes.
- On September 30, 2021, Suncor assumed the role of operator of the Syncrude asset, a critical step towards driving greater integration, efficiencies and competitiveness across all Suncor-operated assets in the region, further strengthening the company's regional oil sands advantage. The joint venture owners expect that Suncor assuming operatorship will capture increased value for the owners through improved operational performance, efficiency and competitiveness.
- Fort Hills resumed two-train operations late in the fourth quarter of 2021. The company is on track to operate the Fort Hills asset at average utilization rates of 90% throughout 2022.
- In 2021, the company focused on the safety and reliability of its operations by successfully executing the largest annual maintenance program in the company's history across its asset base, including the significant five-year planned turnaround at Oil Sands Base plant Upgrader 2 and significant turnaround activities at Syncrude. Due to the impacts of the COVID-19 pandemic in the Fort McMurray region the company responded quickly and decisively by staggering its planned turnarounds at Oil Sands Base plant Upgrader 2 and Syncrude, to support the safe and efficient completion of the turnaround activities at the two assets.
- During the year, Suncor, together with eight Indigenous communities, announced the formation of Astisiy, which acquired a 15% equity interest in the Northern Courier Pipeline. The Northern Courier Pipeline, which connects the Fort Hills asset to Suncor's East Tank Farm, is now operated by Suncor and is expected to provide the eight Indigenous communities with reliable income for decades.
- In 2021, Suncor, together with industry partners representing over 90% of Canada's oil sands production, announced the Oil Sands Pathways to Net Zero alliance whose initiative is aimed at working collectively with the federal and Alberta governments to achieve net-zero GHG emissions from oil sands operations by 2050. The Pathways initiative will explore several parallel pathways to address GHG emissions, including the creation of a Carbon Capture, Utilization and Storage trunkline connected to a carbon sequestration hub to enable multi-sector 'tie-in' projects as well as the implementation of other next-generation technologies.

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

Strategy and Investment Update

Suncor holds one of the largest resource positions in the Athabasca oil sands. The company has developed a unique asset base within the Athabasca oil sands and has established a regional advantage given the close proximity of the company's assets to one another, which the company can leverage to maximize the value of its production volumes. The company is committed to delivering safe, reliable, low-cost production, while moving forward in the areas of technology and innovation and environmental sustainability. The Oil Sands regional advantage is strengthened by the company's marketing and trading expertise, including the midstream and logistics network, which secures market access, optimizes price realizations associated with the marketing of crude oil, byproducts and natural gas supply, manages inventory levels, and limits the impacts of external market factors, including pipeline disruptions, lack of egress or outages at refining customers.

Suncor remains focused on operational excellence and increasing the reliability and utilization across our assets. The company will continue to operate in a safe and reliable manner, while optimizing production. The company is committed to maximizing utilization of our Upgraders to produce the highest-value barrels, and this will be further enabled by optimizing transfers on the interconnecting pipelines between Suncor's Oil Sands Base and Syncrude. In 2022, the company expects increased production at each asset, strong upgrader utilization and higher margins for the company.

The company's regional oil sands advantage was further reinforced during the year with the company taking over as operator of the Syncrude asset on September 30, 2021. With the assumption of operatorship, the company is on track to realize the expected $100 million of annual gross synergies for the joint venture owners in 2022, with an additional $200 million expected to be realized through 2023–2024.

The primary focus for cost management in 2022 will be to continue efforts to sustainably reduce controllable operating costs through implementation of digital technologies that will facilitate the transition to the workplace of the future, bolster operational excellence and drive additional value. Through the advancement of Suncor's digital transformation, the company continues to work to reduce the cost structure of running its business while increasing productivity. Looking ahead, the company aims to lower aggregate Oil Sands cash operating costs per barrel, driven by higher production volumes and cost-reduction synergies.

Capital allocation continues to focus on asset sustainment and maintenance projects designed to maintain safe and reliable operations, as well as advancing high-value economic investment projects. The Oil Sands capital program in 2022 is heavily weighted towards asset sustainment and maintenance activities that reinforce the safety, long-term reliability and efficiency of the assets, including the first major turnaround at Firebag in 10 years.

At Syncrude, planned economic spend in 2022 includes the Mildred Lake West Extension project, which is expected to sustain Syncrude's current production levels by extending the life of the North Mine using existing extraction and upgrading facilities while minimizing the environmental impacts of building new infrastructure. The project is expected to come online in late 2025.

Planned economic spend for the company's In Situ assets will be focused on maintaining production capacity at existing facilities through continued development of reserves by building new well pads. Suncor is also working on developing incremental debottlenecks to maximize the value of the Firebag asset. Debottlenecking capacity and timing will depend on economic conditions, and can be supported by integrated well pad development and Solvent steam-assisted gravity drainage (SAGD) technologies.

The company continues to invest in projects that are economically robust, sustainably focused and technologically progressive. The investment to replace the coke-fired boilers with a cogeneration facility at Oil Sands Base is expected to provide reliable steam generation required for Suncor's extraction and upgrading activities, at a lower cost and with significantly lower carbon emissions. The cogeneration facility is also expected to generate electricity that will be transmitted to Alberta's power grid, lowering the carbon intensity of the Alberta power grid while delivering value to Suncor. Construction of the cogeneration facility at Oil Sands Base was restarted in 2021 and the facility is expected to be in service between 2024 and 2025.

The company's ability to leverage technology and innovation is at the core of our strategy. Deploying additional technology projects at the company's Oil Sands assets, such as digital mine optimization and the deployment of autonomous haulage systems (AHS) is expected to improve operational efficiencies and drive additional value for the company.

These initiatives, combined with continued advancement of digital technologies, will contribute in part to the company's incremental free funds flow target.

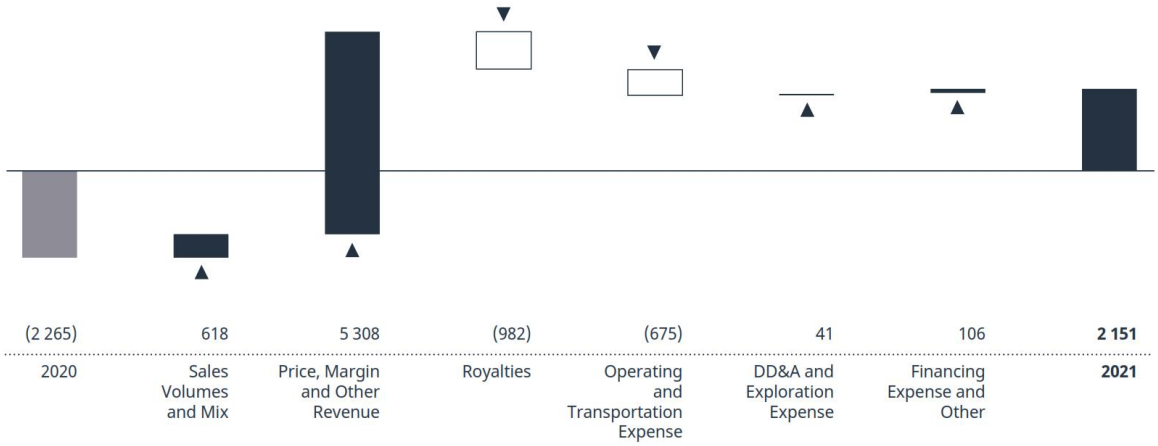
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Financial Highlights

Year ended December 31 ($ millions)	2021	2020	2019
Gross revenues	**19 920**	10 617	18 347
Less: Royalties	**(1 523)**	(95)	(917)
Operating revenues, net of royalties	**18 397**	10 522	17 430
Net earnings (loss)	**2 147**	(3 796)	(427)
Adjusted for:			
Unrealized loss on risk management activities (1)	**4**	13	50
Asset impairment (2)	**—**	1 376	2 959
Provision for pipeline project	**—**	142	—
Impact of income tax rate adjustment on deferred taxes (3)	**—**	—	(910)
Adjusted operating earnings (loss) (4)	**2 151**	(2 265)	1 672
Adjusted funds from operations (4)	**6 846**	1 986	6 061

(1) Beginning in 2021, the company revised its calculation of adjusted operating earnings (loss), a non-GAAP financial measure, to exclude unrealized (gains) losses on derivative financial instruments that are recorded at fair value in other income (loss) to better align the earnings impact of the activity with the underlying items being risk-managed. Prior period comparatives have been restated to reflect this change.
(2) In 2019, the company recorded impairment charges of $3.716 billion ($2.803 billion after-tax) on its share of the Fort Hills assets due to continued volatility in the crude oil price environment, resulting in a decline in forecasted long-term heavy crude oil prices.
(3) In 2019, the company recorded a $910 million deferred income tax recovery in the Oil Sands segment 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%.
(4) Non-GAAP financial measures. See the Advisories – Non-GAAP Financial Measures section of this MD&A.

Bridge Analysis of Adjusted Operating (Loss) Earnings ($ millions)(1)(2)



(1) For an explanation of the construction of this bridge analysis, see the Advisories – Non-GAAP Financial Measures section of this MD&A.
(2) Beginning in 2021, the company revised its calculation of adjusted operating earnings (loss), a non-GAAP financial measure, to exclude unrealized (gains) losses on derivative financial instruments that are recorded at fair value in other income (loss) to better align the earnings impact of the activity with the underlying items being risk-managed. Prior period comparatives have been restated to reflect this change.

The Oil Sands segment had adjusted operating earnings of $2.151 billion in 2021, compared to an adjusted operating loss of $2.265 billion in 2020. The increase was primarily due to higher realized crude prices, as crude benchmarks were significantly impacted in the prior year as a result of the COVID-19 pandemic and OPEC+ supply issues, and increased production, partially offset by higher royalties associated with higher crude price realizations and increased operating expenses.

Oil Sands net earnings were $2.147 billion in 2021, compared to a net loss of $3.796 billion in 2020. In addition to the factors impacting adjusted operating earnings (loss) described above, net earnings for 2021 included a $5 million ($4 million after-tax) unrealized loss on risk management activities, compared to a loss of $18 million ($13 million after-tax) in 2020. 2020 net earnings also included the impact of a non-cash impairment charge of $1.821 billion ($1.376 billion after-tax) on its share of the Fort Hills assets due to a decline in forecasted crude oil prices in 2020 as a result of decreased global demand due to the COVID-19 pandemic and changes to its capital, operating and production plans. In 2020, the company also recorded a provision to transportation expense for $186 million ($142 million after-tax) related to the Keystone XL pipeline project.

Adjusted funds from operations for the Oil Sands segment were $6.846 billion in 2021, compared to $1.986 billion in 2020, and were influenced by the same factors that impacted adjusted operating earnings (loss) noted above.

Production Volumes[1][2]

Year ended December 31 (mbbls/d)	2021	2020	2019
SCO and diesel production[3]	**483.5**	477.5	497.0
Internally consumed diesel and internal transfers[4][5]	**(14.9)**	(11.3)	(11.4)
Upgraded production – net SCO and diesel	**468.6**	466.2	485.6
Bitumen production	**178.8**	127.2	184.8
Internal bitumen transfers[5]	**(3.2)**	—	—
Non-upgraded bitumen production	**175.6**	127.2	184.8
Total Oil Sands production	**644.2**	593.4	670.4

(1) Bitumen from Oil Sands Base operations is upgraded, while bitumen production from In Situ operations is either upgraded or sold directly to customers, including Suncor's own refineries, with SCO and diesel yields of approximately 79% of bitumen feedstock input. Fort Hills finished bitumen is sold directly to customers, including Suncor's own refineries. The majority of the bitumen produced at Syncrude is upgraded to sweet SCO and a small amount of diesel, at an approximate yield of 85%.

(2) Beginning in 2020, the company revised the presentation of its production volumes to aggregate production from each asset into the categories of "Upgraded production" and "Non-upgraded bitumen production" to better reflect the integration among the company's assets with no impact to overall production volumes. Comparative periods have been updated to reflect this change.

(3) Combined upgrader utilization rates are calculated using total upgraded production, inclusive of internally consumed diesel and internal transfers.

(4) Both Oil Sands operations and Syncrude produce diesel, which is internally consumed in mining operations, and Fort Hills and Syncrude use internally produced diesel from Oil Sands Base within their mining operations. In 2021, Oil Sands operations production volumes included 9,500 bbls/d of internally consumed diesel, of which 7,200 bbls/d was consumed at Oil Sands Base, 1,500 bbls/d was consumed at Fort Hills and 800 bbls/d was consumed at Syncrude. Syncrude production volumes included 2,600 bbls/d of internally consumed diesel.

(5) Internal feedstock transfers between Oil Sands operations and Syncrude through the interconnecting pipelines are included in gross SCO and bitumen production volumes. In 2021, Oil Sands operations included 2,600 bbls/d of SCO and 600 bbls/d of bitumen that was transferred to Suncor's share of Syncrude through the interconnecting pipelines. Syncrude production included 200 bbls/d of SCO and 2,600 bbls/d of bitumen that was transferred to Oil Sands Base through the interconnecting pipelines.

The company's net SCO production was 468,600 bbls/d in 2021 compared to 466,200 bbls/d in 2020, marking the second-best year of SCO production in the company's history. During 2021, the company achieved a combined upgrader utilization rate of 87% compared to 85% in the prior year, reflecting maintenance activities in both periods. In 2021, Suncor completed the largest annual planned maintenance program in the company's history, including the significant five-year planned turnaround at Oil Sands Base plant Upgrader 2 and significant turnaround activities at Syncrude.

Non-upgraded bitumen production increased to 175,600 bbls/d in 2021 from 127,200 bbls/d in the prior year, with the increase driven by record production from the company's In Situ assets, including at Firebag. During the year, the increase in non-upgraded bitumen production to market was further supported by strong mining performance at Oil Sands Base, which resulted in less Firebag volumes utilized at the Upgrader and overall higher Oil Sands operations production volumes. The prior year was impacted by maintenance activities at Firebag and MacKay River.

The increase in non-upgraded bitumen production was partially offset by a decrease in production at Fort Hills in 2021 compared to the prior year, reflecting a change in the mine ramp-up strategy. The strategy was principally focused on building ore inventory levels which are required to operate the plant at 90% of nameplate capacity on a two-train operation. The additional overburden removal was required earlier than expected to provide full access to exposed ore and maintain slope integrity. The company executed the mine ramp-up strategy and resumed two-train operations late in the fourth quarter of 2021, and the company is on track to operate the Fort Hills asset at average utilization rates of 90% throughout 2022. Higher production from Fort Hills in 2020 reflected Fort Hills operating on two primary extraction trains early in the year.

Sales Volumes and Mix[1]

Year ended December 31 (mbbls/d)	2021	2020	2019
SCO and diesel	**465.7**	467.9	483.6
Non-upgraded bitumen	**183.8**	125.6	187.5
Total	**649.5**	593.5	671.1

(1) Beginning in 2020, the company revised the presentation of its sales volumes to aggregate sales from each asset into the categories of "SCO and diesel" and "Non-upgraded bitumen" to better reflect the integration among the company's assets with no impact to overall sales volumes. Comparative periods have been updated to reflect this change.

SCO and diesel sales volumes were 465,700 bbls/d in 2021, compared to 467,900 bbls/d in 2020, reflecting a build of inventory in 2021, compared to a slight draw in the prior year.

Non-upgraded bitumen sales volumes increased to 183,800 bbls/d in 2021, from 125,600 bbls/d in the prior year, consistent with the increase in production, and reflecting a draw of inventory in 2021, compared to a build of inventory in the prior year.

Price Realizations(1)(2)(3)

Year ended December 31 Net of transportation costs, but before royalties ($/bbl)	**2021**	2020	2019
SCO and diesel	**77.73**	43.83	70.68
Non-upgraded bitumen	**53.80**	22.37	45.71
Crude sales basket (all products)	**70.96**	39.29	63.70
Crude sales basket, relative to WTI	**(14.20)**	(13.51)	(12.00)

(1) Contains non-GAAP financial measures. See the Advisories – Non-GAAP Financial Measures section of this MD&A.
(2) Beginning in 2020, the company revised the presentation of its price realizations to aggregate price realizations from each asset into the categories of "SCO and diesel" and "Non-upgraded bitumen" to better reflect the integration among the company's assets with no impact to overall price realizations. Comparative periods have been updated to reflect this change.
(3) Beginning in 2020, the company revised its "Non-upgraded bitumen" price realization to include midstream activities employed to optimize its logistics capacity and more accurately reflect the performance of the product stream. Comparative periods have been restated to reflect this change.

Oil Sands price realizations increased in 2021 compared to 2020, in line with the improved commodity price environment. The prior year was impacted by the significant decline in transportation fuel demand due to the impacts of the COVID-19 pandemic and OPEC+ supply issues at the beginning of 2020. Price realizations improved in 2021, in line with increased commodity demand, optimism relating to vaccine rollouts and OPEC+ supply management actions.

Royalties

Royalties for the Oil Sands segment were higher in 2021 compared to 2020, primarily due to higher crude price realizations, increased royalties for In Situ operations due to Firebag reaching the higher post-payout phase of its royalty agreement, and increased sales volumes.

Expenses and Other Factors

Total Oil Sands operating and transportation expenses for 2021 were higher relative to 2020, as described in detail below. See the Cash Operating Costs section below for further details. In 2020, the relief provided under the Government of Canada's Emergency Wage Subsidy (CEWS) program, in addition to safe-mode costs associated with the deferral of capital projects and additional costs incurred in response to the COVID-19 pandemic have been included in operating and transportation expenses by asset. These recoveries and costs, however, have been excluded from the company's cash operating costs per barrel metrics for comparability purposes.

At Oil Sands operations, operating costs increased compared to the prior year, primarily due to increased natural gas prices, increased maintenance costs and higher production.

At Fort Hills, operating costs in 2021 increased when compared to the prior year, reflecting increased mine activity to remove overburden and increase ore inventory in preparation for the transition back to a two-train operation in the fourth quarter of 2021. Operating costs during 2021 were also impacted by higher natural gas prices compared to the prior year and increased maintenance costs.

Syncrude operating costs in 2021 increased compared to the prior year, primarily due to higher maintenance costs, production and natural gas prices.

In 2021, increased natural gas prices resulted in an increase of Oil Sands segment operating costs by $295 million compared to 2020.

Oil Sands transportation costs in 2021 increased from the prior year, primarily due to higher sales volumes.

DD&A and exploration expenses for 2021 were comparable to 2020.

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Cash Operating Costs

Year ended December 31	2021	2020	2019
Oil Sands operating, selling and general expense (OS&G)	**8 056**	7 169	8 027
Oil Sands operations cash operating costs(1) reconciliation			
Oil Sands operations OS&G	**4 710**	4 292	4 639
Non-production costs(2)	**(199)**	(107)	(179)
Excess power capacity and other(3)	**(375)**	(248)	(241)
Inventory changes	**21**	(3)	48
Oil Sands operations cash operating costs(1) ($ millions)	**4 157**	3 934	4 267
Oil Sands operations production volumes(4) (mbbls/d)	**439.2**	380.9	414.5
Oil Sands operations cash operating costs(1) ($/bbl)	**25.90**	28.20	28.20
Fort Hills cash operating costs(1) reconciliation			
Fort Hills OS&G	**897**	761	921
Non-production costs(2)	**(118)**	(52)	(115)
Inventory changes	**(15)**	(11)	9
Fort Hills cash operating costs(1) ($ millions)	**764**	698	815
Fort Hills production volumes (mbbls/d)	**50.7**	58.1	85.3
Fort Hills cash operating costs(1) ($/bbl)	**41.35**	32.80	26.15
Syncrude cash operating costs(1) reconciliation			
Syncrude OS&G	**2 449**	2 116	2 467
Non-production costs(2)	**(234)**	(66)	(156)
Syncrude cash operating costs(1)(5) ($ millions)	**2 215**	2 050	2 311
Syncrude production volumes(4) (mbbls/d)	**172.4**	165.7	172.3
Syncrude cash operating costs(1) ($/bbl)	**35.20**	33.80	36.75

(1) Non-GAAP financial measures. Related per barrel amounts contain 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 adjustments, research costs, project startup costs and adjustments to reflect the cost of internal transfers in the receiving asset at the cost of production. In addition, for 2020, non-production costs include safe-mode costs associated with the deferral of capital projects and additional costs incurred in response to the COVID-19 pandemic. Non-production costs in 2020 also include the relief provided under the CEWS program. Non-production costs at Fort Hills and Syncrude also include, but are not limited to, 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.

(4) Beginning in 2020, Oil Sands operations cash operating costs are based on production volumes, which include internally consumed diesel produced at Oil Sands Base and consumed at Fort Hills, Syncrude and Oil Sands Base, while prior periods presented exclude internally consumed diesel at Oil Sands Base from production volumes. Prior periods were not restated due to the immaterial impact of the change in presentation. Also, beginning in 2020, Syncrude cash operating costs are based on production volumes, which include internally consumed diesel, while prior periods presented exclude internally consumed diesel from production. Prior periods were not restated due to the immaterial impact of the change in presentation.

(5) Beginning in 2020, the company revised the methodology for calculating Syncrude cash operating costs to better align with the Oil Sands operations and Fort Hills cash operating costs methodology. Prior period Syncrude cash operating costs had previously included future development costs and have been restated to reflect this change.

Oil Sands operations cash operating costs per barrel (1) in 2021 decreased to $25.90, compared to $28.20 in the prior year due to increased production, partially offset by higher operating, selling and general expenses, as detailed above. Total Oil Sands operations cash operating costs increased to $4.157 billion from $3.934 billion in the prior year.

Oil Sands operations non-production costs, which are excluded from cash operating costs, were higher in the current year compared to the prior year, as the prior year included relief provided under the CEWS program, partially offset by safe-mode and COVID-19 response costs. The current year non-production costs were also impacted by higher share-based compensation expenses associated with the increase in the company's share price in the current year compared to the prior year.

Excess power capacity and other costs at Oil Sands operations for 2021 were higher than the prior year, due mainly to an increase in excess power revenues resulting from higher power prices.

Fort Hills cash operating costs per barrel (1) averaged $41.35 in 2021, compared to $32.80 in 2020, reflecting higher operating, selling and general expenses, as detailed above, and decreased production. Non-production costs were higher in 2021 compared to the prior year primarily due to the prior year including the relief provided under the CEWS program, partially offset by safe-mode and COVID-19 response costs, an increase in excess power revenues resulting from higher power prices, and a larger adjustment for internally sourced diesel, which is adjusted to reflect internally produced diesel from Oil Sands operations at the cost of production.

Syncrude cash operating costs per barrel (1) averaged $35.20 in 2021, compared to $33.80 in the previous year, due to an increase in operating, selling and general expenses, as detailed above, partially offset by higher production volumes. Non-production costs were higher in 2021 compared to 2020, as the prior year included the relief provided under the CEWS program, and were also impacted by higher long-term incentive expenses in the current year compared to the prior year. Suncor's share of total Syncrude cash operating costs increased to $2.215 billion from $2.050 billion in 2020.

Planned Maintenance

Significant planned turnaround activities at Firebag are scheduled to commence the second quarter of 2022 and are expected to be completed in the third quarter. Planned annual coker maintenance at Oil Sands Base Upgrader 2 is scheduled to commence in the second quarter of 2022 and is expected to be completed in the third quarter. Additional maintenance is scheduled at Upgrader 1 in the third and fourth quarters of 2022. Planned maintenance is scheduled to commence at Syncrude late in the first quarter of 2022, and planned turnaround activities are scheduled to commence in the third quarter of 2022. Planned maintenance is scheduled at Fort Hills in the second and fourth quarters of 2022. The anticipated impact of these maintenance events has been reflected in the company's 2022 guidance.

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

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EXPLORATION AND PRODUCTION

2021 Highlights

- E&P adjusted funds from operations (1) increased to $1.478 billion in 2021, compared to $1.054 billion in the prior year. E&P adjusted operating earnings(1) increased to $890 million in 2021, compared to $13 million in the prior year, and E&P net earnings increased to $1.285 billion in 2021, compared to a net loss of $832 million in the prior year.
- In 2021, Suncor and the co-owners of the Terra Nova project finalized an agreement to restructure the project ownership and move forward with the ALE Project, which is expected to extend production life by approximately 10 years. As a result of the agreement, Suncor increased its ownership in the project by approximately 10% to 48%.
- Buzzard Phase 2, which will extend production life of the existing Buzzard field, achieved first oil in the fourth quarter of 2021. Buzzard Phase 2 is expected to reach its peak production in 2022, adding approximately 12,000 boe/d gross (approximately 3,500 boe/d net to Suncor) to existing Buzzard production.
- The company completed the sale of its 26.69% working interest in the Golden Eagle Area Development for gross proceeds of US$250 million net of closing adjustments and other closing costs, in addition to future contingent consideration of up to US$50 million. The effective date of the sale was January 1, 2021. The sale reinforces Suncor's continued focus on capital discipline and enables the company to allocate resources to core assets and maximize shareholder returns.

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 E&P business is strengthened by the company's marketing and trading expertise, which secures market access in both domestic and international markets, optimizes price realizations, manages inventory levels and limits the impacts of external market factors.

The company continues to exercise capital discipline, carefully evaluating future projects and being disciplined in the deployment of capital. In 2021, a decision was made to restructure the Terra Nova project ownership and move forward with the ALE Project. As a result of the agreement, Suncor increased its ownership in the project by approximately 10% to 48% in exchange for a cash payment from the exiting owners. The agreement also includes the previously disclosed royalty and financial support from the Government of Newfoundland and Labrador. The Terra Nova Floating, Production, Storage and Offloading facility is dry-docked in Spain undergoing maintenance work and is expected to sail back to Canada for a safe return to operations before the end of 2022. The Terra Nova ALE Project, which is expected to extend the life of the Terra Nova field by approximately a decade, adding an additional 70 million barrels of resource for the partnership, is expected to provide significant returns to Suncor and many benefits to the Newfoundland and Labrador and Canadian economies in the form of taxes, royalties and employment.

At West White Rose, in 2021, Suncor entered into a conditional agreement to increase its interest in the White Rose assets subject to a number of conditions, including an economic restart decision for the West White Rose Project by mid-2022. Should the conditions be met, Suncor has agreed to increase its ownership interest in the White Rose assets by 12.5% to approximately 40% in exchange for a cash payment by the operator to Suncor.

The company continues to focus on strategic production growth of its E&P assets, with 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 development activities are planned to continue in 2022, but are expected to be limited to development drilling at Hebron, Hibernia, Fenja and Oda. The Rosebank future development project, which is one of the largest remaining resources in the U.K North Sea, is currently in the pre-sanction phase.

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

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Financial Highlights

Year ended December 31 ($ millions)	2021	2020	2019
Gross revenues[1]	**2 736**	1 851	3 372
Less: Royalties[1]	**(236)**	(95)	(302)
Operating revenues, net of royalties	**2 500**	1 756	3 070
Net earnings (loss)	**1 285**	(832)	1 005
Adjusted for:			
Asset (reversal) impairment[2]	**(168)**	845	393
Gain on significant disposals[3]	**(227)**	—	(187)
Impact of income tax rate adjustments on deferred income taxes[4]	**—**	—	(70)
Adjusted operating earnings[5]	**890**	13	1 141
Adjusted funds from operations[5]	**1 478**	1 054	2 143

(1) Production, revenues and royalties from the company's Libya operations have been presented in the E&P section of this MD&A on an economic basis and exclude an equal and offsetting gross up of revenues and royalties of $242 million in 2021, $48 million in 2020 and $303 million in 2019, which is required for presentation purposes in the company's financial statements under the working-interest basis.

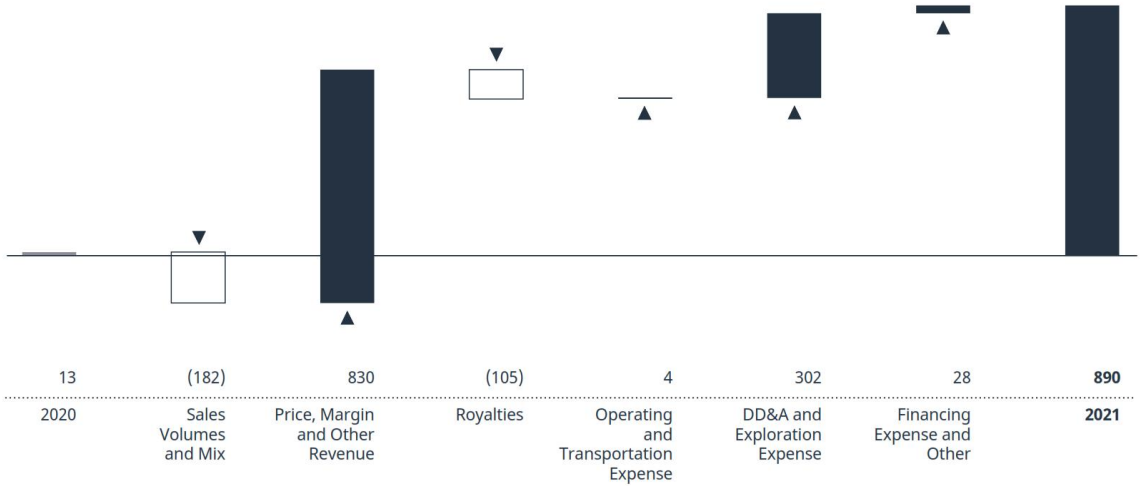
(2) During 2019, the company recorded non-cash impairment charges of $521 million ($393 million after-tax) against White Rose due to increased capital cost estimates at the West White Rose Project.

(3) 2019 included a gain of $65 million ($48 million after-tax) related to the sale of certain non-core assets. Also in 2019, Suncor sold its 37% interest in Canbriam Energy Inc. for total proceeds and an equivalent gain of $151 million ($139 million after-tax), which had previously been written down to nil in 2018 following the company's assessment of forward natural gas prices and the impact on estimated future cash flows.

(4) In 2019, the company recorded a $70 million deferred income tax recovery in the E&P segment 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%.

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

Bridge Analysis of Adjusted 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.

Adjusted operating earnings were $890 million for E&P in 2021, compared to $13 million in the prior year, with the increase due to higher realized crude prices and lower DD&A and exploration expense, partially offset by lower production volumes and higher royalties. In 2021, crude oil and refined production realizations increased significantly compared to the prior year, which was significantly impacted by the COVID-19 pandemic and an increase in OPEC+ crude supply.

Net earnings for E&P were $1.285 billion in 2021, compared to a net loss of $832 million in 2020. In addition to the factors impacting adjusted operating earnings described above, net earnings in 2021 included a non-cash impairment reversal of $221 million ($168 million after-tax) against the company's share of the Terra Nova assets and a gain of $227 million ($227 million after-tax) on the sale of the company's interest in the Golden Eagle Area Development. Net earnings in 2020 included non-cash impairment charges of $1.119 billion ($845 million after-tax) against the company's share of the White Rose and Terra Nova assets.

Adjusted funds from operations were $1.478 billion in 2021, compared to $1.054 billion in 2020. The increase was largely due to the same factors that impacted adjusted operating earnings described above, excluding the impacts of DD&A and exploration expense.

Volumes(1)

Year ended December 31	2021	2020	2019
E&P Canada (mbbls/d)	**54.4**	59.7	59.9
E&P International (mboe/d)	**33.1**	42.0	46.9
Total production (mboe/d)	**87.5**	101.7	106.8
Total sales volumes (mboe/d)	**82.8**	102.6	106.0

(1) Beginning in 2020, the company revised the presentation of its production volumes to aggregate production from each asset into the categories of "E&P Canada" and "E&P International" to simplify the presentation. Comparative periods have been updated to reflect this change.

E&P Canada production volumes averaged 54,400 bbls/d in 2021, compared to 59,700 bbls/d the prior year, primarily due to natural declines. Both periods were impacted by the absence of production from Terra Nova as the asset has remained off-line since the fourth quarter of 2019.

E&P International production volumes averaged 33,100 boe/d in 2021, compared to 42,000 boe/d in 2020, with the decrease primarily related to natural declines at Buzzard and Oda, partially offset by increased liftings in Libya in 2021 compared to 2020.

E&P sales volumes averaged 82,800 mboe/d in 2021, compared to 102,600 mboe/d in the prior year, consistent with the decrease in production and including a build of inventory in the U.K. and in Canada associated with the timing of cargo sales at year-end.

Price Realizations(1)

Year ended December 31 Net of transportation costs, but before royalties	2021	2020	2019
E&P Canada – Crude oil and natural gas liquids ($/bbl)	**84.70**	49.69	84.86
E&P International(2) ($/boe)	**82.16**	50.28	81.22

(1) Contains non-GAAP financial measures. See the Advisories – Non-GAAP Financial Measures section of this MD&A.
(2) E&P International price realizations include the company's U.K. and Norway assets and exclude Libya for all periods presented.

Price realizations at E&P Canada and E&P International increased in 2021 from the prior year, in line with the improved commodity price environment. The prior year was impacted by the significant decline in transportation fuel demand due to the impacts of the COVID-19 pandemic. Price realizations improved in 2021, in line with increased commodity demand, optimism relating to vaccine rollouts and OPEC+ supply management actions.

Royalties

E&P royalties in 2021 were higher than the prior year primarily due to the increase in price realizations.

Expenses and Other Factors

Operating expenses for 2021 were comparable to the prior year.

DD&A and exploration expenses in 2021 decreased from the prior year as a result of the absence of DD&A on the company’s White Rose assets in 2021, as a result of impairment charges in the fourth quarter of 2020, lower DD&A on the Golden Eagle Area Development asset as a result of the asset sale that occurred during the year, lower sales volumes and a decline in exploration activities.

Non-Cash Asset Impairment Reversal

During the third quarter of 2021, the company recorded a non-cash impairment reversal of $221 million ($168 million after-tax) on its share of the Terra Nova assets as a result of the ALE Project moving forward and the benefit of royalty and financial support from the Government of Newfoundland and Labrador.

Planned Maintenance of Operated Assets

There are no other planned maintenance activities at Terra Nova once the asset returns to operations, which is expected to occur before the end of 2022.

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REFINING AND MARKETING

2021 Highlights

- Suncor leveraged its refinery product mix, midstream logistics flexibility, strong domestic sales network including integration with its retail network, export capabilities and storage capacity to deliver refinery crude throughput of 415,500 bbls/d in 2021, and industry-leading utilization rates of 89%, compared to 407,000 bbls/d and 88% in the prior year.
- The company's Canadian refineries outperformed the Canadian refining industry average by over 12% (1) during the year, despite turnarounds being completed across all of the company's refineries.
- R&M delivered $3.255 billion in adjusted funds from operations (2) in 2021, compared to $1.708 billion in the prior year. R&M adjusted operating earnings(2) increased to $2.170 billion in 2021, compared to $882 million in the prior year, and R&M net earnings increased to $2.178 billion in 2021, compared to $866 million in the prior year. In 2021, the impact of the FIFO method of inventory valuation, relative to an estimated LIFO(3) method, had a positive impact to net earnings, adjusted operating earnings and adjusted funds from operations of $795 million after-tax, compared to a negative after-tax impact of $384 million in 2020.

Strategy and Investment Update

The R&M business is a key component of Suncor's integrated business model and serves to maximize Suncor's integrated returns by extending the value chain from oil sands production to the end customer, providing the vital link between Suncor's resource base and consumer demand for high-quality refined products. The company's integrated model is supported by the unique advantages of our R&M business, including the key structural advantages of our refineries, our extensive marketing and logistics capabilities and secured market access, enhanced by our marketing and trading expertise.

The company's refineries are equipped with several key structural advantages, including Suncor's feedstock advantage, which enables the company to process a heavy crude slate with a high-quality output, while operating in geographically advantaged markets with consistent access to low cost feedstock. The company aims to achieve consistent operational excellence at its refineries through strong reliability and industry-leading refinery utilizations, allowing the company to provide a reliable supply of products to its secured and competitive sales channels, while also operating at optimal levels of utilization to provide reliable offtake for a portion of the production from the Oil Sands segment. The company's sales channels include the Petro-Canada™ brand, Canada's #1 fuel brand,(4) with nearly 1,600 retail sites and over 300 PETRO-PASS™ sites located in key metropolitan areas across Canada.

The R&M business is strengthened by the company's marketing and trading expertise , by optimizing the supply of crude and natural gas liquids 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. The marketing and logistics organization also moves Suncor's refinery production to market and ensures supply to Suncor's branded retail and wholesale marketing channels. The business ensures reliable natural gas supply to Suncor's upstream and downstream operations and generates incremental revenue through trading and asset optimization. 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.

The company continues to pursue midstream opportunities to expand the company's market reach, strengthen the company's sales channels and maximize price realizations, including increasing incremental revenue through increased products trading activities and exploring additional pipeline arrangements that provide feedstock optionality to our refineries.

Suncor continues to focus on operational excellence, including maximizing reliability and utilization, while practicing operating cost and capital discipline. In 2022, Suncor expects refinery throughput to return to 2019 levels, positioning the company to capture improving margins and demand, supported by its secured and competitive sales channels. The R&M capital program in 2022 is heavily weighted towards asset sustainment and maintenance activities focused on ongoing sustainment and enhancement to refinery operations, further driving reliable operations. The company plans to make economic investments in expansions of its retail and wholesale network, further supporting the company's connection to its customers and increasing its sales channels.

Suncor remains committed to supporting consumers' transition to a low-emissions future through investments in initiatives designed to provide low-carbon solutions to our customers. Canada's Electric Highway™, the coast-to-coast network of fast-charging electric vehicle stations across Canada, is one way that we are supporting consumers' transition to a low-emissions future.

(1) Source: Canada Energy Regulator – https://www.cer-rec.gc.ca/en/data-analysis/energy-commodities/crude-oil-petroleum-products/statistics/weekly-crude-run-summary-data/index.html.
(2) Non-GAAP financial measures. See the Advisories – Non-GAAP Financial Measures section of this MD&A.
(3) The estimated impact of the LIFO method is a non-GAAP financial measure. See the Advisories – Non-GAAP Financial Measures section of this MD&A.
(4) Based on Kent (a Kalibrate company) survey data for year-end 2020.

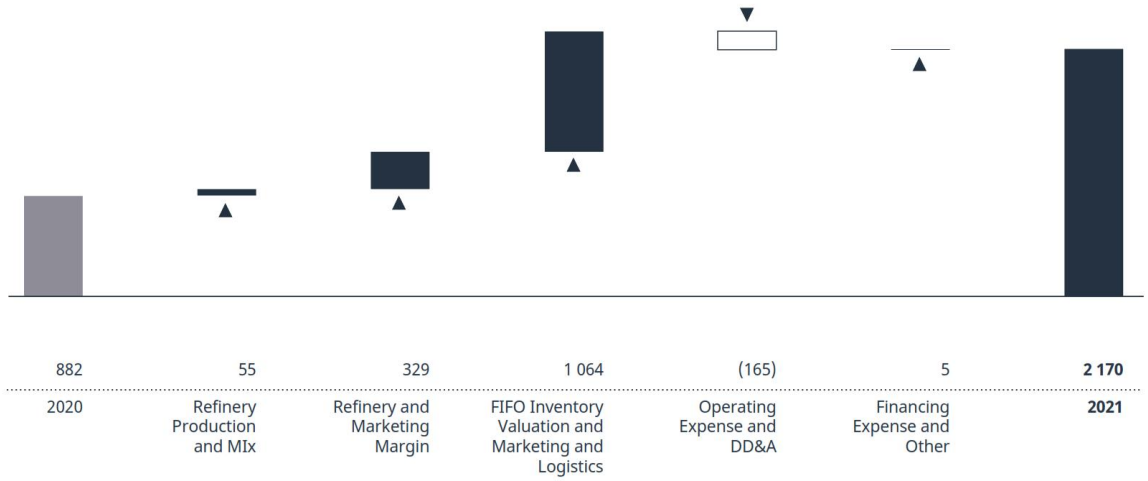
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Financial Highlights

Year ended December 31 ($ millions)	2021	2020	2019
Operating revenues	**22 915**	15 272	22 304
Net earnings	**2 178**	866	3 000
Adjusted for:			
Unrealized (gain) loss on risk management activities (1)	**(8)**	16	10
Impact of income tax rate adjustments on deferred taxes (2)	—	—	(88)
Adjusted operating earnings (3)	**2 170**	882	2 922
Adjusted funds from operations (3)	**3 255**	1 708	3 863

(1) Beginning in 2021, the company revised its calculation of adjusted operating earnings, a non-GAAP financial measure, to exclude unrealized (gains) losses on derivative financial instruments that are recorded at fair value in other income (loss) to better align the earnings impact of the activity with the underlying items being risk-managed. Prior period comparatives have been restated to reflect this change.
(2) In 2019, the company recorded an $88 million deferred income tax recovery in the R&M segment 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%.
(3) Non-GAAP financial measures. See the Advisories – Non-GAAP Financial Measures section of this MD&A.

Bridge Analysis of Adjusted Operating Earnings ($ millions)(1)(2)



(1) For an explanation of the construction of this bridge analysis, see the Advisories – Non-GAAP Financial Measures section of this MD&A.
(2) Beginning in 2021, the company revised its calculation of adjusted operating earnings, a non-GAAP financial measure, to exclude unrealized (gains) losses on derivative financial instruments that are recorded at fair value in other income (loss) to better align the earnings impact of the activity with the underlying items being risk-managed. Prior period comparatives have been restated to reflect this change.

R&M contributed annual adjusted operating earnings of $2.170 billion in 2021, compared with $882 million in 2020. The increase was primarily due to a significant increase in crude and refined product benchmarks compared to the prior year, which resulted in a FIFO inventory valuation gain compared to a FIFO inventory valuation loss in the prior year, and an increase in refining and marketing margins, partially offset by an increase in operating expenses.

Net earnings in 2021 were $2.178 billion compared to net earnings of $866 million in 2020, and were impacted by the same factors as adjusted operating earnings described above. In addition to the factors impacting adjusted operating earnings, net earnings in 2021 included a $10 million ($8 million after-tax) unrealized gain on risk management activities, compared to a $21 million ($16 million after-tax) loss in the prior year.

R&M achieved an annual adjusted funds from operations of $3.255 billion in 2021, compared to $1.708 billion in 2020, due primarily to the same factors that impacted adjusted operating earnings described above.

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Volumes

Year ended December 31	2021	2020	2019
Crude oil processed (mbbls/d)			
Eastern North America	**202.8**	201.0	203.3
Western North America	**212.7**	206.0	235.6
Total	**415.5**	407.0	438.9
Refinery utilization(1)(2) (%)			
Eastern North America	**91**	91	92
Western North America	**87**	86	98
Total	**89**	88	95
Refined product sales (mbbls/d)			
Gasoline	**225.8**	214.1	246.6
Distillate(3)	**228.5**	215.7	218.1
Other	**74.1**	73.6	74.7
Total	**528.4**	503.4	539.4
Refining and marketing gross margin – FIFO (4)(5) ($/bbl)	**36.85**	25.30	40.45
Refining and marketing gross margin – LIFO (4)(5) ($/bbl)	**30.90**	28.65	36.80
Refining operating expense(5) ($/bbl)	**5.95**	5.50	5.35

(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) The Edmonton refinery crude processing capacity has increased to 146,000 bbls/d in 2021 from 142,000 bbls/d in 2020.
(3) Beginning in 2020, to better reflect the increasing integration of the company's assets, the company revised the presentation of its refined product sales volumes to include Oil Sands diesel that is purchased and marketed by the Refining and Marketing segment.
(4) Beginning in 2020, refining and marketing gross margins have been revised to better reflect the refining, product supply and rack forward businesses. Prior periods have been restated to reflect this change.
(5) Contains non-GAAP financial measures. See the Advisories – Non-GAAP Financial Measures section of this MD&A.

Refinery crude throughput increased to 415,500 bbls/d and refinery utilization averaged 89% in 2021, compared to refinery crude throughput of 407,000 bbls/d and refinery utilization of 88% in 2020, reflecting strong utilizations across all refineries in 2021, despite the impacts of planned turnaround activities across all of its refineries during the year. The prior year reflected reduced rates as a result of a decrease in consumer demand for transportation fuels due to the impacts of the COVID-19 pandemic.

Total refined product sales increased to 528,400 bbls/d in 2021, compared to 503,400 bbls/d in 2020. Strong utilizations during the year, increased demand and secured sales channels positioned the company to capture the improved business environment.

Refining and Marketing Gross Margins (1)

Refining and marketing gross margins were influenced by the following:

- On a LIFO(2) basis, Suncor's refining and marketing gross margin increased to $30.90/bbl in 2021, from $28.65/bbl in the prior year due to improved benchmark crack spreads and the widening of heavy crude oil differentials, partially offset by the impact a stronger Canadian dollar in relation to the U.S. dollar. Suncor's refining and marketing gross margin also reflects Suncor's feedstock advantage, which enables the company to process heavier crude oil, marketing and logistics capabilities and strong sales channels within its integrated retail and wholesale networks.

- On a FIFO basis, Suncor's refining and marketing gross margin increased to $36.85/bbl in 2021, from $25.30/bbl in the prior year due to the same factors noted above, in addition to FIFO inventory valuation impacts. In 2021, the impact of the FIFO method of inventory valuation, relative to an estimated LIFO(2) accounting method, resulted in an after-tax gain of $795 million. In 2020, FIFO resulted in an after-tax loss of $384 million, for an overall favourable year-over-year impact of $1.064 billion after-tax, including the impact of short-term commodity risk management activities.

Expenses and Other Factors

R&M operating and transportation expenses increased compared to the prior year. The increase was primarily due to increased natural gas and power prices in the current year, cost reductions in response to the COVID-19 pandemic impacting the prior year, including the relief provided under the CEWS program, a higher shared-based compensation expense in the current year as a result of an increase in the company's share price and increased throughput. Refining operating expense per barrel(1) was $5.95 in 2021, compared to $5.50 in the prior year, with the increase primarily due to increased absolute costs, partially offset by higher crude throughput.

DD&A expense in 2021 was comparable to the prior year.

Planned Maintenance

Planned turnaround maintenance is scheduled for the Edmonton, Montreal and Sarnia refineries in the second quarter of 2022. The anticipated impact of these maintenance events has been reflected in the company's 2022 guidance.

(1) Contains non-GAAP financial measures. See the Advisories – Non-GAAP Financial Measures section of this MD&A.
(2) The estimated impact of the LIFO method is a non-GAAP financial measure. See the Advisories – Non-GAAP Financial Measures section of this MD&A.

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CORPORATE AND ELIMINATIONS

2021 Highlights

- Suncor exceeded its return to shareholder targets for the year, returning a total of $3.9 billion to shareholders, through $1.6 billion of dividends paid and $2.3 billion in share repurchases, repurchasing the company's common shares at the highest rate in the company's history. In 2021, since the start of the NCIB program in February 2021, the company repurchased approximately 84 million of its common shares at an average price of $27.45 per common share, or the equivalent of 5.5% of Suncor's common shares as at January 31, 2021.
- Demonstrating management's confidence in the company's ability to generate sustainable and increasing cash flows and its commitment to increasing shareholder returns, the company increased its dividend per share by 100% in the fourth quarter, reinstating the quarterly dividend to $0.42 per common share, returning it to 2019 levels.
- In 2021, Suncor accelerated its net debt(1) reduction, reducing debt at the highest ever annual pace, resulting in a reduction of net debt by $3.7 billion to $16.1 billion, returning to 2019 net debt levels.
- In 2021, demonstrating management's confidence in the company's ability to generate cash flows, the company cancelled $2.8 billion in bi-lateral credit facilities that were no longer required, as they were entered into in March and April of 2020 to ensure access to adequate financial resources in connection with the COVID-19 pandemic.
- Subsequent to the end of the year, the company continued to make meaningful progress towards its net debt reduction and shareholder return targets by completing an early redemption of its outstanding US$182 million 4.50% notes, originally scheduled to mature in the second quarter of 2022, and repurchasing an additional 0.5% of its common shares up to February 7, 2022. The company also renewed its NCIB, beginning February 8, 2022, and ending February 7, 2023, for the repurchase of up to approximately 5% of Suncor's issued and outstanding common shares as at January 31, 2022.
- In 2021, company announced its new strategic objective to become a net-zero GHG emissions company by 2050 and to substantially contribute to society's net-zero ambitions. The company set near-term absolute emissions reduction goals to align with its objective to reach net-zero emissions and plans to meet its goals by reducing its base business emissions, investing in low-emissions ventures and technologies and taking actions that reduce others' emissions.
- During 2021, the company increased its investments in clean technology, including an equity investment in Svante Inc., a Canadian carbon capture company that plans to develop technology to capture CO_2 from industrial processes at reduced costs, and increased its investment in the Varennes Carbon Recycling facility.

Strategy and Investment Update

Delivering competitive and sustainable returns to shareholders is a top priority of the company and we aim to maximize shareholder returns by focusing on operational excellence, underpinned by safety above all else, capital discipline through investments in high-value projects and technology, and our commitment to environmental stewardship and sustainability.

Suncor continues to progress its digital transformation and implement new digital technologies across the enterprise to help improve the safety, productivity, reliability and environmental performance of our operations. The company anticipates this will enable operational efficiencies that will provide further structural cost savings. In 2022, the company expects to continue to advance its digital transformation through initiatives such as supply chain optimization initiatives and core business systems aimed at improving operational efficiencies, which are expected to contribute to Suncor's incremental free funds flow targets. The company anticipates that the implementation of digital technologies will improve the safety of our company, facilitate the transition to the workplace of the future, bolster operational excellence and drive additional value.

Returning cash to shareholders and strengthening the balance sheet continues to be a top priority for Suncor; proven by the company's progress in 2021 related to debt reductions, dividend increase and share repurchases. The company will remain disciplined in its plans to reduce debt towards its 2025 targeted net debt range of $12–$15 billion. Looking ahead in 2022, the company plans to allocate its annual free funds flow, after its dividend, evenly between share buybacks and debt reductions. Subsequent to the end of the year, a renewal of the company's NCIB was approved, beginning February 8, 2022, and ending February 7, 2023, for the repurchase of up to approximately 5% of Suncor's issued and outstanding common shares as at January 31, 2022.

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

In 2021, Suncor announced its new strategic objective to become a net-zero GHG emissions company by 2050 and to substantially contribute to society's net-zero ambitions. To align with this objective, the company has set a near-term goal to reduce annual emissions by 10 megatonnes across its value chain by 2030 to replace its previous goal of reducing its emissions intensity by 30% by 2030. Suncor plans to achieve this by making pragmatic and highly economic investments that are in line with, or synergistic with, our core capabilities, including leveraging our existing expertise in low-carbon power, renewable fuels and expanding into clean hydrogen production. This includes construction of the Forty Mile Wind Power Project, a 200 MW renewable energy power project in southern Alberta, which is expected to generate significant value through sustainable power generation and retention of the generated carbon credits for utilization in Suncor's upstream business. The project is currently under construction and is expected to be completed and operational late in 2022, contributing to the company's incremental free funds flow and emissions reduction goals, while meeting growing customer demand for lower-carbon energy.

Investments in new technologies that leverage Suncor's existing core capabilities, and provide new sustainable energy sources, are key to Suncor's expansion of its low-emissions energy business. Strategic equity investments with two biofuel companies that are currently progressing renewable fuel technology projects are examples of how the company is progressing this goal. The first investment, the Varennes Carbon Recycling facility, a biofuel plant in Varennes, Quebec, that is currently under construction, is designed to convert commercial and industrial non-recyclable waste into biofuels and renewable chemicals. In addition, the company also owns an equity investment in LanzaJet, Inc., a company working to bring sustainable aviation fuel and renewable diesel to the commercial market. Fabrication of a commercial biorefinery plant near Soperton, Georgia, is well underway and is expected to be on-stream in late-2022 and will allow Suncor to supply sustainable low-emissions aviation fuel to customers. From a design perspective, both projects are being constructed using a design that is expected to be able to be replicated, enabling quick expansion to capture the sizable growth opportunities projected for renewable liquid fuels should economics be attractive. Suncor believes these investments complement its existing biofuels business and demonstrates Suncor's commitment to being a leader in the global energy expansion.

In 2021, Suncor invested in Svante Inc., a Canadian carbon capture company. With support from Suncor and other companies, Svante Inc. is accelerating the commercial deployment of its technology to capture CO_2 from heavy-emitting industries like cement, steel, and oil and gas production at a lower cost than current methods. Carbon capture is a strategic technology area for Suncor to reduce greenhouse gas emissions in Suncor's base business and produce blue hydrogen as an energy product. In addition, Suncor and ATCO Ltd. announced a partnership on a potential world-scale clean hydrogen project to be developed in Alberta, Canada. A sanctioning decision is expected in 2024 and the facility could be operational as early as 2028, provided it has the required regulatory and fiscal support to render it economic. The project would significantly advance Suncor and Alberta's hydrogen strategy, generate substantial economic activity and make a large contribution towards Suncor and society's net-zero ambitions.

Financial Highlights

Year ended December 31 ($ millions)	**2021**	2020	2019
Net loss	**(1 491)**	(557)	(679)
Adjusted for:			
Unrealized foreign exchange gain on U.S. dollar denominated debt	**(101)**	(286)	(590)
Restructuring charge	**126**	—	—
Loss on early repayment of long-term debt	**60**	—	—
Impact of income tax rate adjustments on deferred income taxes (1)	—	—	(48)
Adjusted operating loss (2)	**(1 406)**	(843)	(1 317)
Corporate and Renewables	***(1 262)***	*(936)*	*(1 113)*
Eliminations - Intersegment profit (eliminated) realized	***(144)***	*93*	*(204)*
Adjusted funds used in operations (2)	**(1 322)**	(872)	(1 249)

(1) In 2019, the company recorded a $48 million 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%.
(2) Non-GAAP financial measures. See the Advisories – Non-GAAP Financial Measures section of this MD&A.

Year ended December 31	**2021**	2020	2019
Renewable Energy power generation marketed (gigawatt hours) (1)	**183**	200	184

(1) Power generated includes curtailed production for which the company was compensated.

Corporate and Renewables

Corporate incurred an adjusted operating loss of $1.262 billion in 2021, compared with an adjusted operating loss of $936 million in 2020, with the increased adjusted operating loss primarily due to a share-based compensation expense in 2021 versus a share-based compensation recovery in 2020. The adjusted operating loss in 2020 included favourable income tax settlements and relief provided under the CEWS program. Suncor capitalized $144 million of its borrowing costs in 2021, compared to $120 million in 2020, as part of the cost of major development assets and construction projects in progress.

Eliminations – Intersegment Profit Realized (Eliminated)

Eliminations reflect the deferral or realization of profit on crude oil sales from Oil Sands to Suncor's refineries. Consolidated profits are only realized when the refined products produced from internal purchases of crude feedstock have been sold to third parties. In 2021, the company deferred $144 million of after-tax intersegment profit, compared to a realization of profit of $93 million in the prior year. The deferral of profit in 2021 was driven by the increase in Oil Sands price realizations in 2021, as lower margin crude refinery feedstock sourced internally from Oil Sands was sold and replaced by higher margin crude inventory, resulting in a deferral of profit at the enterprise level.

Adjusted funds used in operations for the Corporate and Eliminations segment were $1.322 billion in 2021, compared to $872 million in 2020, and were influenced by the same factors that impacted adjusted operating loss, adjusted for the non-cash component of share-based compensation expense.

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5. FOURTH QUARTER 2021 ANALYSIS

Financial and Operational Highlights

Three months ended December 31 ($ millions, except as noted)	2021	2020
Net earnings (loss)		
Oil Sands	**896**	(293)
Exploration and Production	**465**	(379)
Refining and Marketing	**450**	268
Corporate and Eliminations	**(258)**	236
Total	**1 553**	(168)
Adjusted operating earnings (loss) (1)(2)		
Oil Sands	**898**	(130)
Exploration and Production	**238**	44
Refining and Marketing	**437**	280
Corporate and Eliminations	**(279)**	(303)
Total	**1 294**	(109)
Adjusted funds from (used in) operations (1)		
Oil Sands	**2 175**	729
Exploration and Production	**425**	312
Refining and Marketing	**765**	415
Corporate and Eliminations	**(221)**	(235)
Total adjusted funds from operations	**3 144**	1 221
Changes in non-cash working capital	**(529)**	(407)
Cash flow provided by operating activities	**2 615**	814
Production volumes (mboe/d)		
Oil Sands – Upgraded – net SCO and diesel	**515.0**	514.3
Oil Sands – Non-upgraded bitumen	**150.9**	157.2
Exploration and Production	**77.4**	97.7
Total	**743.3**	769.2

(1) Non-GAAP financial measures. See the Advisories – Non-GAAP Financial Measures section of this MD&A.
(2) Beginning in 2021, the company revised its calculation of adjusted operating earnings (loss), a non-GAAP financial measure, to exclude unrealized (gains) losses on derivative financial instruments that are recorded at fair value in other income (loss) to better align the earnings impact of the activity with the underlying items being risk-managed. Prior period comparatives have been restated to reflect this change.

Net Earnings (Loss)

Suncor's consolidated net earnings for the fourth quarter of 2021 were $1.553 billion, compared to a net loss of $168 million for the prior year quarter. Net earnings were primarily influenced by the same factors that impacted adjusted operating earnings described subsequently in this section.

Other items affecting net earnings (loss) over these periods included:

- The unrealized foreign exchange gain on the revaluation of U.S. dollar denominated debt recorded in financing expenses was $25 million ($21 million after-tax) for the fourth quarter of 2021, compared to a gain of $602 million ($539 million after-tax) for the fourth quarter of 2020.
- The unrealized gain on risk management activities recorded in other income (loss) was $14 million ($11 million after-tax) for the fourth quarter of 2021, compared to a $44 million ($33 million after-tax) loss for the fourth quarter of 2020.
- The gain of $227 million ($227 million after-tax) on the sale of the company's interest in the Golden Eagle Area Development, which was completed early in the fourth quarter of 2021 and recorded in the E&P segment.
- During the fourth quarter of 2020, the company recorded non-cash impairment charges of $559 million ($423 million after-tax) against its share of the White Rose assets, in the E&P segment, as a result of the high degree of uncertainty surrounding the future of the West White Rose Project.
- In the fourth quarter of 2020, the company recorded a provision to transportation expense for $186 million ($142 million after-tax) related to the Keystone XL pipeline project in the Oil Sands segment.

Adjusted Funds From Operations and Cash Flow provided by Operating Activities

Adjusted funds from operations were $3.144 billion ($2.17 per common share) in the fourth quarter of 2021, compared to $1.221 billion ($0.80 per common share) in the fourth quarter of 2020. Adjusted funds from operations were influenced by the same factors impacting adjusted operating earnings (loss) noted below.

Cash flow provided by operating activities, which includes changes in non-cash working capital, was $2.615 billion ($1.80 per common share) for the fourth quarter of 2021, compared to $814 million ($0.53 per common share) in the prior year quarter. In addition to the factors noted below, cash flow provided by operating activities was further impacted by a use of cash associated with the company's working capital balances in both periods. The use of cash in the fourth quarter of 2021 was primarily due to an increase in accounts receivable related to increased sales and an increase in crude oil price realizations during the quarter, and a decrease in accounts payable and accrued liabilities, partially offset by an increase in taxes payable related to the company's 2021 income tax expense, which is payable in early 2022.

Segmented Analysis

Oil Sands

The Oil Sands segment had adjusted operating earnings of $898 million in the fourth quarter of 2021, compared to an adjusted operating loss of $130 million in the prior year quarter. The increase was primarily due to higher realized crude prices, as crude benchmarks were lower in the prior year quarter as a result of the COVID-19 pandemic, partially offset by an increase in royalties and operating expenses.

The company's net SCO production of 515,000 bbls/d in the fourth quarter of 2021 was comparable to 514,300 bbls/d in the prior year quarter, resulting in a combined upgrader utilization rate of 96% in the fourth quarter of 2021 compared to 95% in the prior year quarter. Increased SCO production at Oil Sands Base, with increased In Situ bitumen production being diverted to upgrading to maximize higher-value SCO production, was largely offset by lower production at Syncrude due to unplanned maintenance, which was completed subsequent to the quarter. Production in the prior year quarter was impacted by planned maintenance at Oil Sands Base, which was completed early in the quarter.

The company's non-upgraded bitumen production was 150,900 bbls/d in the fourth quarter of 2021, compared to 157,200 bbls/d in the prior year quarter, with the decrease primarily due to lower production at Fort Hills, which resumed two-train operations late in the fourth quarter of 2021. The company is on track to operate the Fort Hills asset at average utilization rates of 90% throughout 2022.

In the fourth quarter of 2021, non-upgraded bitumen production from the company's In Situ assets was comparable to the prior year quarter, with an overall increase in production volumes being offset by increased Firebag bitumen production being diverted to upgrading. The fourth quarter of 2021 was impacted by fewer maintenance activities at Firebag compared to the prior year quarter.

SCO and diesel sales volumes were 496,100 bbls/d in the fourth quarter of 2021, compared to 495,600 bbls/d in the prior year quarter, consistent with the increase in upgraded production.

Non-upgraded bitumen sales volumes increased to 176,700 bbls/d in the fourth quarter of 2021, compared to 139,600 bbls/d in the prior year quarter, due to a draw in inventory in the fourth quarter of 2021 compared to a build of inventory in the prior year quarter, partially offset by the decrease in production in the current quarter.

Exploration and Production

Adjusted operating earnings for the E&P segment in the fourth quarter of 2021 increased to $238 million compared to $44 million in the prior year quarter, with the increase primarily due to higher realized crude prices and lower DD&A, partially offset by lower sales volumes.

Production volumes for E&P Canada were 47,600 bbls/d in the fourth quarter of 2021, compared to 56,800 bbls/d in the prior year quarter, primarily due to natural declines. Both periods were impacted by the absence of production from Terra Nova as the asset has remained off-line since the fourth quarter of 2019.

E&P International production was 29,800 boe/d in the fourth quarter of 2021, compared to 40,900 boe/d in the prior year quarter. Production volumes decreased in the current quarter primarily due to the absence of production from the Golden Eagle Area Development, as the sale of the asset was completed early in the fourth quarter of 2021, and natural declines.

E&P sales volumes decreased to 67,200 boe/d in the fourth quarter of 2021, compared to 98,800 boe/d in the prior year quarter, due to the decrease in production and a build of inventory at E&P Canada associated with the timing of cargo sales at year-end.

Refining and Marketing

R&M adjusted operating earnings in the fourth quarter of 2021 increased to $437 million from $280 million in the prior year quarter. The increase was primarily due to higher refining and marketing margins as a result of significantly higher crack spread benchmarks in the fourth quarter of 2021 compared to the prior year quarter. Adjusted operating earnings included a FIFO inventory valuation gain of $106 million after-tax on the increase in crude and refined product benchmarks in the fourth quarter of 2021, compared to a $44 million after-tax gain in the prior year quarter. Adjusted operating earnings were unfavourably impacted by increased operating expenses in the fourth quarter of 2021 compared to the prior year quarter.

Refinery crude throughput increased to 447,000 bbls/d and refinery utilization was 96% in the fourth quarter of 2021, compared to refinery crude throughput of 438,000 bbls/d and refinery utilization of 95% in the prior year quarter, reflecting strong utilizations across all refineries. Refined product sales in the fourth quarter of 2021 increased to 550,100 bbls/d, compared to 508,800 bbls/d in the prior year quarter. Strong utilizations during the quarter, increased demand and secured sales channels positioned the company to capture the improved business environment.

Corporate and Eliminations

Corporate and Eliminations incurred an adjusted operating loss of $279 million for the fourth quarter of 2021, compared to an adjusted operating loss of $303 million for the prior year quarter, with the increased loss attributable to favourable tax settlements in the prior year quarter, partially offset by a decrease in interest expense on long-term debt as a result of debt repayments that occurred throughout 2021. Suncor capitalized $38 million of its borrowing costs in the fourth quarter of 2021 as part of the cost of major development assets and construction projects in progress, compared to $26 million in the prior year quarter.

Eliminations reflect the deferral or realization of profit or loss on crude oil sales from Oil Sands to Suncor's refineries. Consolidated profits and losses are only realized when the refined products produced from internal purchases of crude feedstock have been sold to third parties. During the fourth quarter of 2021, the company realized $25 million of after-tax intersegment profit compared to a deferral of $21 million of after-tax intersegment profit in the prior year quarter.

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6. QUARTERLY FINANCIAL DATA

Financial Summary

Three months ended ($ millions, unless otherwise noted)	**Dec 31 2021**	Sept 30 2021	June 30 2021	Mar 31 2021	Dec 31 2020	Sept 30 2020	June 30 2020	Mar 31 2020
Total production (mboe/d)								
Oil Sands	**665.9**	605.1	615.7	690.6	671.5	519.0	553.7	630.1
Exploration and Production	**77.4**	93.5	84.0	95.3	97.7	97.2	101.8	109.7
	743.3	698.6	699.7	785.9	769.2	616.2	655.5	739.8
Revenues and other income								
Operating revenues, net of royalties	**11 149**	10 145	9 159	8 679	6 615	6 427	4 229	7 391
Other income (loss)	**10**	68	(66)	(43)	(21)	30	16	365
	11 159	10 213	9 093	8 636	6 594	6 457	4 245	7 756
Net earnings (loss)	**1 553**	877	868	821	(168)	(12)	(614)	(3 525)
per common share[1] (dollars)	**1.07**	0.59	0.58	0.54	(0.11)	(0.01)	(0.40)	(2.31)
Adjusted operating earnings (loss)[2][3]	**1 294**	1 043	722	746	(109)	(338)	(1 345)	(421)
per common share[3][4][5] (dollars)	**0.89**	0.71	0.48	0.49	(0.07)	(0.22)	(0.88)	(0.28)
Adjusted funds from operations[2]	**3 144**	2 641	2 362	2 110	1 221	1 166	488	1 001
per common share[4][5] (dollars)	**2.17**	1.79	1.57	1.39	0.80	0.76	0.32	0.66
Cash flow provided by (used in) operating activities	**2 615**	4 718	2 086	2 345	814	1 245	(768)	1 384
per common share[5] (dollars)	**1.80**	3.19	1.39	1.54	0.53	0.82	(0.50)	0.91
ROCE[4] (%) for the twelve months ended	**8.6**	4.5	1.9	(1.4)	(6.9)	(10.2)	(7.5)	(1.3)
ROCE excluding impairments and impairment reversals[4][6](%) for the twelve months ended	**8.2**	4.9	2.6	(0.6)	(2.9)	(1.3)	1.0	7.0
After-tax unrealized foreign exchange gain (loss) on U.S. dollar denominated debt	**21**	(257)	156	181	539	290	478	(1 021)
Common share information (dollars)								
Dividend per common share	**0.42**	0.21	0.21	0.21	0.21	0.21	0.21	0.47
Share price at the end of trading								
Toronto Stock Exchange (Cdn$)	**31.65**	26.26	29.69	26.27	21.35	16.26	22.89	22.46
New York Stock Exchange (US$)	**25.03**	20.74	23.97	20.90	16.78	12.23	16.86	15.80

(1) Represented on a basic and diluted per share basis.
(2) Non-GAAP financial measures. See the Advisories – Non-GAAP Financial Measures section of this MD&A. Adjusted 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. Adjusted Funds from operations for each quarter are defined and reconciled to GAAP measures in the Non-GAAP Financial Measures Advisory section of each Quarterly Report in respect of the relevant quarter, with such information being incorporated by reference herein and available on SEDAR at www.sedar.com.
(3) Beginning in 2021, the company revised its calculation of adjusted operating earnings (loss), a non-GAAP financial measure, to exclude unrealized (gains) losses on derivative financial instruments that are recorded at fair value in other income (loss) to better align the earnings impact of the activity with the underlying items being risk-managed. Prior period comparatives have been restated to reflect this change.
(4) Contains non-GAAP financial measures. See the Advisories – Non-GAAP Financial Measures section of this MD&A. Non-GAAP measures included in ROCE and ROCE excluding impairments are defined and reconciled to GAAP measures in the Non-GAAP Financial Measures Advisory section of each Quarterly Report in respect of the relevant quarter, with such information being incorporated by reference herein and available on SEDAR at www.sedar.com.
(5) Represented on a basic per share basis.
(6) ROCE excluding impairments would have been 5.1% for the first quarter of 2020 excluding the impacts of the $1.116 billion deferred tax recovery for the Alberta corporate income tax rate change in the second quarter of 2019.

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Business Environment

Three months ended (average for the period ended, except as noted)		**Dec 31 2021**	Sept 30 2021	June 30 2021	Mar 31 2021	Dec 31 2020	Sept 30 2020	June 30 2020	Mar 31 2020
WTI crude oil at Cushing	US$/bbl	**77.15**	70.55	66.05	57.80	42.65	40.95	27.85	46.10
Dated Brent crude	US$/bbl	**79.70**	73.45	68.85	60.85	44.20	43.00	29.20	50.15
Dated Brent/Maya FOB price differential	US$/bbl	**8.60**	7.80	6.20	4.70	3.30	3.50	2.70	15.95
MSW at Edmonton	Cdn$/bbl	**93.25**	83.75	77.25	66.55	50.25	51.30	30.20	52.00
WCS at Hardisty	US$/bbl	**62.50**	56.95	54.60	45.40	33.35	31.90	16.35	25.60
Light/heavy crude oil differential for WTI at Cushing less WCS at Hardisty	US$/bbl	**(14.65)**	(13.60)	(11.45)	(12.40)	(9.30)	(9.05)	(11.50)	(20.50)
SYN-WTI (differential) premium	US$/bbl	**(1.80)**	(1.60)	0.35	(3.50)	(3.05)	(2.45)	(4.55)	(2.70)
Condensate at Edmonton	US$/bbl	**79.10**	69.20	66.40	58.00	42.55	37.55	22.20	46.20
Natural gas (Alberta spot) at AECO	Cdn$/mcf	**4.70**	3.60	3.10	3.15	2.65	2.25	2.00	2.05
Alberta Power Pool Price	Cdn$/MWh	**107.30**	100.35	104.50	95.45	46.15	43.85	29.90	67.05
New York Harbor 2-1-1 crack (1)	US$/bbl	**20.65**	20.90	20.35	15.60	9.85	10.20	12.20	14.75
Chicago 2-1-1 crack (1)	US$/bbl	**16.90**	20.45	20.25	13.40	7.95	7.75	6.75	9.75
Portland 2-1-1 crack (1)	US$/bbl	**25.35**	26.70	24.55	15.80	13.15	12.55	12.20	18.30
Gulf Coast 2-1-1 crack (1)	US$/bbl	**19.65**	19.55	18.25	14.45	9.00	8.55	9.00	13.00
U.S. Renewable Volume Obligation	US$/bbl	**6.10**	7.33	8.13	5.50	3.48	2.64	2.21	1.58
Exchange rate	US$/Cdn$	**0.79**	0.79	0.81	0.79	0.77	0.75	0.72	0.74
Exchange rate (end of period)	US$/Cdn$	**0.79**	0.78	0.81	0.80	0.78	0.75	0.73	0.71

(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 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 (Loss)

Trends in Suncor's quarterly revenue, net earnings (loss) and adjusted funds from operations are driven primarily by production volumes, which can be significantly impacted by major maintenance events, changes in commodity prices and crude price differentials, refining crack spreads and foreign exchange rates as described in the Financial Information section of this MD&A. Trends in Suncor's quarterly net earnings (loss) and adjusted funds from operations are also affected by other significant events impacting operations, such as the COVID-19 pandemic beginning in the first quarter of 2020, operational incidents and the Government of Alberta's mandatory production curtailments that were implemented during 2019 and suspended effective December 2020.

In addition to the impacts of changes in production volumes and business environment, net earnings (loss) over the last eight quarters were affected by the following events or significant adjustments:

- During the fourth quarter of 2021, the company recorded a gain of $227 million ($227 million after-tax) on the sale of the company's interest in the Golden Eagle Area Development, in the E&P segment.
- During the third quarter of 2021, the company recorded a non-cash impairment reversal of $221 million ($168 million after-tax) against its share of the Terra Nova assets, in the E&P segment, as a result of the ALE Project moving forward and the benefit of royalty and financial support from the Government of Newfoundland and Labrador.
- During the third quarter of 2021, the company recorded a loss of $80 million ($60 million after-tax) for early repayment of long-term debt in financing expenses in the Corporate and Eliminations segment.

- During the first quarter of 2021, the company recorded a restructuring charge of $168 million ($126 million after-tax) related to workforce reductions in operating, selling and general expenses in the Corporate and Eliminations segment.

- During the fourth quarter of 2020, the company recorded non-cash impairment charges of $559 million ($423 million after-tax) against its share of the White Rose assets, in the E&P segment, as a result of the high degree of uncertainty surrounding the future of the West White Rose Project.

- During the fourth quarter of 2020, the company recorded a provision to transportation expense for $186 million ($142 million after-tax) related to the Keystone XL pipeline project in the Oil Sands segment.

- During the first quarter of 2020, the company recorded non-cash impairment charges of $1.821 billion ($1.376 billion after-tax) on its share of the Fort Hills assets, in the Oil Sands segment, and $560 million ($422 million after-tax) against its share of the White Rose and Terra Nova assets, in the E&P segment, due to a decline in forecasted crude oil prices in 2020 as a result of decreased global demand due to the impacts of the COVID-19 pandemic and changes to their respective capital, operating and production plans.

- During the first quarter of 2020, the company recorded a hydrocarbon inventory write-down to net realizable value of $240 million ($177 million after-tax) in the Oil Sands segment, and $296 million ($220 million after-tax) in the R&M segment, as a result of a significant decline in benchmarks and demand for crude oil and refined products due to COVID-19 mitigation efforts. The full hydrocarbon inventory write-down amount of $536 million ($397 million after-tax) was included in net earnings but was excluded from adjusted operating earnings and adjusted funds from operations in the first quarter of 2020, and realized through adjusted operating earnings and adjusted funds from operations in the second quarter of 2020 when the product was sold.

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7. CAPITAL INVESTMENT UPDATE

Capital and Exploration Expenditures by Segment

Year ended December 31 ($ millions)	2021	2020	2019
Oil Sands	**3 168**	2 736	3 522
Exploration and Production	**270**	489	1 070
Refining and Marketing	**825**	515	818
Corporate and Eliminations	**292**	186	148
Total capital and exploration expenditures	**4 555**	3 926	5 558
Less: capitalized interest on debt	**(144)**	(120)	(122)
	4 411	3 806	5 436

Capital and Exploration Expenditures by Type, Excluding Capitalized Interest

Year ended December 31, 2021 ($ millions)	Asset Sustainment and Maintenance(1)	Economic Investment(2)	Total
Oil Sands			
Oil Sands Base	*1 216*	*420*	***1 636***
In Situ	*132*	*298*	***430***
Fort Hills	*253*	*-*	***253***
Syncrude	*652*	*97*	***749***
Exploration and Production	*-*	*242*	**242**
Refining and Marketing	*751*	*73*	**824**
Corporate and Eliminations	*53*	*224*	**277**
	3 057	1 354	**4 411**

(1) 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.

(2) 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 2021, Suncor's capital expenditures on property, plant and equipment and exploration activities totalled $4.411 billion, excluding capitalized borrowing costs of $144 million, of which 30% was directed towards economic investment activities and 70% towards asset sustainment and maintenance activities, meeting its planned capital spending program guidance for the year.

The company's 2021 capital expenditures were focused on the safety and reliability of the company's operations, heavily weighted towards asset sustainment and maintenance activities through the largest annual maintenance program in the company's history, which included significant planned turnaround activities across all of its refineries, at Oil Sands operations, including a significant planned turnaround at Oil Sands Base plant Upgrader 2, and a planned turnaround at Syncrude's largest coker. In 2020, due to the impacts of the COVID-19 pandemic, the company deferred, suspended and cancelled certain capital projects or changed the scope of work to reduce costs and to comply with COVID-19 safety measures.

Activity in 2021 included the following:

Oil Sands Base

Oil Sands Base asset sustainment and maintenance capital expenditures were $1.216 billion in 2021 and were primarily focused on ensuring continued safe, reliable and efficient operations. The company's planned maintenance program in 2021 included coker annual planned maintenance in the spring and the significant five-year planned turnaround at Upgrader 2 in the fall.

Oil Sands Base economic capital of $420 million in 2021 was primarily focused on progressing the investment in low-carbon power generation by replacing its coke-fired boilers with a new cogeneration facility.

In Situ

In Situ capital expenditures were $430 million in 2021, of which $298 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. Asset sustainment and maintenance capital expenditures of $132 million were primarily directed towards the company's planned maintenance program, including planned maintenance at Firebag.

Fort Hills

Fort Hills capital expenditures were $253 million in 2021, all directed towards asset sustainment and capital expenditures related to mine and tailings development to support ongoing operations.

Syncrude

Syncrude capital expenditures were $749 million in 2021, the majority of which was directed toward asset sustainment and maintenance capital expenditures that focused on improving asset reliability and included the planned turnaround at Syncrude's largest coker.

Exploration and Production

E&P capital and exploration expenditures were $242 million in 2021, and were focused on economic investment projects, including development drilling at Hebron, and development work at Buzzard Phase 2, the Fenja project and Terra Nova related to the ALE Project. The Terra Nova Floating, Production, Storage and Offloading facility is dry-docked in Spain undergoing maintenance work and is expected to sail back to Canada and return to operations before the end of 2022.

Refining and Marketing

R&M capital expenditures were $824 million in 2021, and were primarily related to the ongoing sustainment of, and enhancement to, refinery and retail operations. This included planned turnaround activities across all of the company's refineries during the year.

Corporate

Corporate capital expenditures were $277 million in 2021, primarily directed towards economic investment projects related to the company's information technology and other corporate initiatives, and the Forty Mile Wind Power Project.

Suncor anticipates 2022 capital expenditures to be directed to the following projects and initiatives:

Oil Sands operations

For 2022, plans for economic investment include capital to progress low-carbon power generation to replace the coke-fired boilers at Oil Sands Base, which is expected to be in-service between 2024 and 2025. Additional investment to maintain production capacity at existing facilities includes the continued development of reserves by building new well pads at In Situ.

Asset sustainment and maintenance capital expenditures for 2022 include spend on tailings management and the significant planned turnaround at Firebag, planned maintenance at Upgrader 1 and planned coker annual maintenance at Upgrader 2.

Fort Hills

Asset sustainment and maintenance capital expenditures for 2022 will focus on ongoing development of mining and tailings management projects to preserve production capacity.

Syncrude

For 2022, plans for economic investment will include capital to progress the Mildred Lake Extension-West mining project. Sustaining capital expenditures for 2022 will focus on planned maintenance and reliability programs aimed at maintaining production capacity, which includes planned maintenance in tailings and a major planned turnaround.

Exploration and Production

Capital expenditures for 2022 are expected to include economic investments at Terra Nova, Hebron, Hibernia, Fenja, Oda, Buzzard and the Rosebank future development project.

Refining and Marketing

The company expects that sustaining capital will focus on ongoing sustainment and enhancement to refinery and retail operations, including planned maintenance activities across the company's refineries. Economic investment projects will be primarily focused on the company's retail and wholesale network.

Corporate

For 2022, the company plans to continue to make economic investments in digital technology initiatives and the Forty Mile Wind Power Project in southern Alberta, which is planned for completion in late 2022.

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8. FINANCIAL CONDITION AND LIQUIDITY

Liquidity and Capital Resources

At December 31 ($ millions, except as noted)	2021	2020	2019
Cash flow provided by (used in)			
Operating activities	**11 764**	2 675	10 421
Investing activities	**(3 977)**	(4 524)	(5 088)
Financing activities	**(7 464)**	1 786	(5 537)
Foreign exchange loss on cash and cash equivalents	**(3)**	(12)	(57)
Increase (decrease) in cash and cash equivalents	**320**	(75)	(261)
Cash and cash equivalents, end of year	**2 205**	1 885	1 960
Return on Capital Employed (%)(1)(2)	**8.6**	(6.9)	4.9
Net debt to adjusted funds from operations (1) (times)	**1.6**	5.1	1.5
Total debt to total debt plus shareholders' equity (1) (%)	**33.4**	37.8	29.9
Net debt to net debt plus shareholders' equity (1)(3) (%)	**30.6**	35.7	27.6
Net debt to net debt plus shareholders' equity - excluding leases (1)(3) (%)	**26.6**	32.1	23.7

(1) Non-GAAP financial measures or contains non-GAAP financial measures. See the Advisories – Non-GAAP Financial Measures section of this MD&A.
(2) ROCE would have been 8.2% for the twelve months ended December 31, 2021, excluding the impact of the impairment reversal of $221 million ($168 million after-tax) in the third quarter of 2021. ROCE would have been (2.9%) for the twelve months ended December 31, 2020, excluding the impact of impairments of $559 million ($423 million after-tax) in the fourth quarter of 2020 and $1.821 billion ($1.376 billion after-tax) and $560 million ($422 million after-tax) in the first quarter of 2020. ROCE would have been 10.0% for the twelve months ended December 31, 2019, excluding the impact of impairments of $3.716 billion ($2.803 billion after-tax) and $521 million ($393 million after-tax) in the fourth quarter of 2019.
(3) Beginning in the first quarter of 2021, the company has added two supplemental debt metrics that reflect additional information that management uses to evaluate capital management.

Cash Flow Provided by Operating Activities

Cash flow provided by operating activities was $11.764 billion in 2021 compared to $2.675 billion in 2020. The increase was primarily due to higher crude oil and refined product realizations reflecting the improved business environment and higher crude production and refinery crude throughput. These factors were partially offset by an increase in royalties, primarily associated with higher crude price realizations, and increased operating expenses. The prior year was negatively impacted by the significant decline in transportation fuel demand, partially offset by cost reductions in response to the COVID-19 pandemic, including the relief provided under the CEWS program.

The current period cash flow provided by operating activities reflects a source of cash in working capital, primarily due to a net increase in taxes payable related to the company's 2021 income tax expense, which is payable in early 2022, and an increase in accounts payable and accrued liabilities, partially offset by an increase in accounts receivable related to an increase in crude oil price realizations during the year. The prior period cash flow provided by operating activities reflects a use of cash in working capital.

Cash Flow Used in Investing Activities

Cash flow used in investing activities was $3.977 billion in 2021 compared to $4.524 billion in 2020. The decrease was primarily due to a decrease in investing working capital related to the timing of payments and proceeds from the sale of the company's interest in the Golden Eagle Area Development. This was partially offset by increased capital expenditures in the current year related to the largest annual maintenance program in the company's history. In 2020, the company reduced, deferred or cancelled certain capital projects in response to the COVID-19 pandemic.

Cash Flow (Used in) Provided by Financing Activities

Cash flow used in financing activities was $7.464 billion in 2021, compared to cash flow provided by financing activities of $1.786 billion in 2020. Cash flow used in financing activities in 2021 was primarily related to the decrease in short-term debt and net long-term debt and increased share repurchases.

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 sufficient capital resources to fund its planned 2022 capital spending program of $4.7 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, if needed, 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, foreign exchange rates and demand for transportation fuels.

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 $2.205 billion at December 31, 2021, are short-term investments with weighted average days to maturity of approximately 20 days. In 2021, the company earned approximately $1 million of interest income on these investments.

Financing Activities

Suncor's interest on debt and lease liabilities (before capitalized interest) in 2021 was $995 million, a decrease from $1.050 billion in 2020, due to a significant decrease in short-term debt during the year and the net reduction of long-term debt that occurred over the course of 2021.

Available lines of credit at December 31, 2021, decreased to $4.247 billion compared to $6.043 billion at December 31, 2020. The decrease in liquidity was primarily due to the cancellation of $2.8 billion in bi-lateral credit facilities that were no longer required as they were entered into in March and April of 2020 to ensure access to adequate financial resources in connection with the COVID-19 pandemic, and a reduction in the size of the company's syndicated credit facilities. The decrease was partially offset by increased credit availability as a result of a lower commercial paper balance. As of December 31, 2021, Suncor had approximately $6.5 billion of liquidity.

A summary of total and unutilized credit facilities at December 31, 2021, is as follows:

($ millions)	2021
Fully revolving and expires in 2025	3 000
Fully revolving and expires in 2024	2 531
Can be terminated at any time at the option of the lenders	1 420
Total credit facilities	6 951
Credit facilities supporting outstanding commercial paper	(1 284)
Credit facilities supporting standby letters of credit	(1 147)
Total unutilized credit facilities[1]	4 520

(1) Available credit facilities for liquidity purposes were $4.247 billion at December 31, 2021 (December 31, 2020 – $6.043 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, 2021, total debt to total debt plus shareholders' equity was 33.4% (December 31, 2020 – 37.8%), a decrease from the prior year due to lower debt levels and higher shareholders' equity as a result of increased net earnings. The company is currently in compliance with all operating covenants as at December 31, 2021.

Change in Net Debt (1)

($ millions)	
Total debt(1) – December 31, 2020	21 699
Net decrease in long-term debt	(1 028)
Net decrease in short-term debt	(2 256)
Increase in lease liability	308
Lease payments	(325)
Foreign exchange on debt, and other	(44)
Total debt(1) – December 31, 2021	18 354
Less: Cash and cash equivalents – December 31, 2021	2 205
Net debt(1) – December 31, 2021	16 149

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

At December 31, 2021, Suncor's net debt was $16.149 billion, compared to $19.814 billion at December 31, 2020. During 2021, net debt decreased by $3.665 billion, primarily due to a net decrease in short-term and long-term debt, lease principal payments made in 2021 and an increase in cash and cash equivalents relative to the prior year, partially offset by additional leases entered into in 2021.

For the year ended December 31, 2021, the company's net debt to adjusted funds from operations measure was 1.6 times, which is lower than management's maximum target of less than 3.0 times.

Subsequent to the end of the year, the company completed an early redemption of its outstanding US$182 million 4.50% notes, originally scheduled to mature in the second quarter of 2022.

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 23, 2022, the company's long-term senior debt ratings are:

Long-Term Senior Debt	Rating	Long-Term Outlook
Standard & Poor's	BBB+	Negative
Dominion Bond Rating Service	A (low)	Stable
Moody's Investors Service	Baa1	Stable

As at February 23, 2022, 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 2021 AIF for a description of credit ratings listed above.

Common Shares

Outstanding Shares

(thousands)	December 31, 2021
Common shares	**1 441 251**
Common share options – exercisable	**28 421**
Common share options – non-exercisable	**8 669**

As at February 23, 2022, the total number of common shares outstanding was 1,431,430,756 and the total number of exercisable and non-exercisable common share options outstanding was 32,937,645. Once exercisable, each outstanding common share option may be exercised for one common share.

Share Repurchases

In the first quarter of 2021, the TSX accepted a notice filed by Suncor to commence an NCIB to repurchase common shares through the facilities of the TSX, NYSE and/or alternative trading systems. The notice provided that, beginning February 8, 2021, and ending February 7, 2022, Suncor may purchase for cancellation up to 44,000,000 common shares, which is equal to approximately 2.9% of Suncor's 1,525,150,794 issued and outstanding common shares as at January 31, 2021.

During the third quarter of 2021, and following the Board's approval to increase the company's share repurchase program to up to approximately 5% of the company's outstanding common shares, Suncor received approval from the TSX to amend its existing NCIB effective as of the close of markets on July 30, 2021, to repurchase common shares through the facilities of the TSX, NYSE and/or alternative trading systems. The amended notice provided that Suncor may increase the maximum number of common shares that may be repurchased in the period beginning February 8, 2021, and ending February 7, 2022, from 44,000,000 common shares, or approximately 2.9% of Suncor's issued and outstanding common shares as at January 31, 2021, to 76,250,000 common shares, or approximately 5% of Suncor's issued and outstanding common shares as at January 31, 2021.

During the fourth quarter of 2021, and following the Board's approval to increase the company's share repurchase program to up to approximately 7% of the company's public float, Suncor received approval from the TSX to amend its existing NCIB effective as of the close of markets on October 29, 2021, to purchase common shares through the facilities of the TSX, NYSE and/or alternative trading systems. The notice provided that Suncor may increase the maximum number of common shares that may be repurchased in the period beginning February 8, 2021, and ending February 7, 2022, from 76,250,000 shares, or approximately 5% of Suncor's issued and outstanding common shares as at January 31, 2021, to 106,700,000, or approximately 7% of Suncor's public float as at January 31, 2021.

Subsequent to the fourth quarter of 2021, and following the Board's approval to renew the company's share repurchase program to repurchase up to approximately 5% of the company's common shares, the TSX accepted a notice filed by Suncor to renew its NCIB to purchase the company's common shares through the facilities of the TSX, NYSE and/or alternative trading systems. The notice provides that, beginning February 8, 2022, and ending February 7, 2023, Suncor may purchase for cancellation up to 71,650,000 common shares, which is equal to approximately 5% of Suncor's issued and outstanding common shares as at the date thereof. As at January 31, 2022, Suncor had 1,435,748,494 common shares issued and outstanding.

Pursuant to Suncor's previous NCIB, as amended on October 29, 2021, Suncor agreed that it would not purchase more than 106,700,000 common shares between February 8, 2021, and February 7, 2022. Between February 8, 2021, and February 7, 2022, and pursuant to Suncor's previous NCIB (as amended), Suncor repurchased 91,046,656 common shares on the open market for approximately $2.554 billion, at a weighted average price of $28.06 per share.

Between February 8, 2022, and February 23, 2022, and pursuant to Suncor's current NCIB (as renewed), Suncor repurchased 3,224,200 shares on the open market for approximately $120 million, at a weighted average price of $37.21 per share.

The actual number of common shares that may be repurchased under the NCIB and the timing of any such purchases will be determined by Suncor. Suncor believes that, depending on the trading price of its common shares and other relevant factors,

repurchasing its common shares represents an attractive investment opportunity and is in the best interests of the company and its shareholders. The company does not expect that the decision to allocate cash to repurchase shares will affect its long-term strategy.

At December 31 ($ millions, except as noted)	**2021**	2020	2019
Share repurchase activities (thousands of common shares)			
Shares repurchased	**83 959**	7 527	55 298
Share repurchase cost	**2 304**	307	2 274
Weighted average repurchase price per share (dollars per share)	**27.45**	40.83	41.12

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)	2022	2023	2024	2025	2026	Thereafter	Total
Long-term debt(1)	969	1 295	720	1 403	1 724	18 836	**24 947**
Decommissioning and restoration costs(2)	305	354	407	401	348	12 012	**13 827**
Long-term contracts, pipeline capacity and energy services commitments(3)	1 957	1 555	1 470	1 323	1 263	8 228	**15 796**
Exploration work commitments(3)	—	20	—	64	1	454	**539**
Lease obligations(4)	459	407	372	342	318	2 633	**4 531**
Other long-term obligations(5)	4	18	18	18	18	—	**76**
Total	**3 694**	**3 649**	**2 987**	**3 551**	**3 672**	**42 163**	**59 716**

(1) Includes long-term debt and interest payments on long-term debt. Refer to note 21 and note 27 of Suncor's 2021 audited Consolidated Financial Statements.
(2) Represents the undiscounted and uninflated amount of decommissioning and restoration costs. Refer to note 24 of Suncor's 2021 audited Consolidated Financial Statements.
(3) Refer to note 32 of Suncor's 2021 audited Consolidated Financial Statements.
(4) Refer to note 21 and note 27 of Suncor's 2021 audited Consolidated Financial Statements.
(5) Includes Libya EPSA signature bonus and merger consent. Please refer to note 22 of Suncor's 2021 audited Consolidated Financial Statements.

Transactions with Related Parties

The company enters into transactions with related parties in the normal course of business. These transactions primarily include sales to associated entities in the company's R&M segment. For more information on these transactions and for a summary of Compensation of Key Management Personnel, refer to note 31 of the 2021 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, 2021, the pre-tax earnings impact of risk management and trading activities was $155 million (2020 – pre-tax earnings of $175 million).

Gains or losses related to derivatives are recorded as Other Income in the Consolidated Statements of Comprehensive Income.

($ millions)	2021	2020
Fair value outstanding, beginning of year	**(121)**	(39)
Cash settlements – paid (received) during the year	**178**	(257)
Changes in fair value recognized in earnings during the year	**(155)**	175
Fair value outstanding, end of year	**(98)**	(121)

The fair value of derivative financial instruments is recorded on the Consolidated Balance Sheets.

Fair value of derivative contracts at December 31 ($ millions)	2021	2020
Accounts receivable	**123**	153
Accounts payable	**(221)**	(274)
	(98)	(121)

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 27 of the company's 2021 audited Consolidated Financial Statements.

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9. ACCOUNTING POLICIES AND CRITICAL ACCOUNTING ESTIMATES

Suncor's significant accounting policies are described in note 3 of the audited Consolidated Financial Statements for the year ended December 31, 2021.

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.

Deferred Tax Related to Assets and Liabilities Arising from a Single Transaction

In May 2021, the IASB issued *Deferred Tax related to Assets and Liabilities arising from a Single Transaction (Amendments to IAS 12)*. The amendments narrowed the scope of the initial recognition exemption to exclude transactions that give rise to equal and offsetting temporary differences. The amendments are effective January 1, 2023, with early adoption permitted. The company does not anticipate any significant impact from these amendments on the consolidated financial statements as a result of the initial application.

Definition of Accounting Estimates

In February 2021, the IASB issued *Definition of Accounting Estimates (Amendments to IAS 8).* The amendments introduced a definition of accounting estimates and included other amendments to help entities distinguish changes in accounting estimates from changes in accounting policies. The amendments are effective January 1, 2023, with early adoption permitted. The company does not anticipate any significant impact from these amendments on the consolidated financial statements as a result of the initial application.

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.

COVID-19

On January 30, 2020, the World Health Organization declared the COVID-19 outbreak a Public Health Emergency of International Concern and, on March 10, 2020, declared it to be a pandemic. Actions taken around the world to help mitigate the spread of COVID-19 include restrictions on travel, quarantines in certain areas, and forced closures for certain types of public places and businesses. These measures have and may continue to have significant disruption to business operations and a significant increase in economic uncertainty, with fluctuating demand for commodities leading to volatile prices and currency exchange rates, and a decline in long-term interest rates. Our operations and business are particularly sensitive to a reduction in the demand for, and prices of, commodities that are closely linked to Suncor's financial performance, including crude oil, refined petroleum products (such as jet fuel and gasoline), natural gas and electricity. The potential direct and indirect impacts of the economic volatility have been considered in management's estimates, and assumptions at period-end have been reflected in our results with any significant changes described in the relevant financial statement note.

The COVID-19 pandemic is an evolving situation that is expected to continue to have widespread implications for our business environment, operations and financial condition. Management cannot reasonably estimate the length or severity of this pandemic, or the extent to which the disruption may materially impact our consolidated statements of comprehensive income (loss), consolidated balance sheets and consolidated statements of cash flows.

Climate Change

Climate change and the transition to a lower-carbon economy from carbon-based sources to alternative energy were considered in preparing the consolidated financial statements. These may have significant impacts on the currently reported amounts of the company's assets and liabilities discussed below and on similar assets and liabilities that may be recognized in the future.

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, 2021, 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, 2021, which could differ significantly from other points in time throughout the year, or future periods. Changes in market and regulatory conditions and assumptions, as well as climate change, and the evolving worldwide demand for energy and global advancement of alternative sources of energy that are not sourced from fossil fuels can materially impact the estimation of net reserves. The timing in which global energy markets transition from carbon-based sources to alternative energy is highly uncertain.

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, income taxes, 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. In addition, climate change, and the evolving worldwide demand for energy and global advancement of alternative sources of energy that are not sourced from fossil fuels could result in a change in assumptions used in determining the recoverable amount and could affect the carrying value and useful life of the related assets. The timing in which global energy markets transition from carbon-based sources to alternative energy is highly uncertain.

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. In addition, climate change, and the evolving worldwide demand for energy and global advancement of alternative sources of energy that are not sourced from fossil fuels could result in a change in assumptions used in determining the carrying value of the liabilities. The timing in which global energy markets transition from carbon-based sources to alternative energy is highly uncertain.

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 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.

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 electricity 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, decisions by OPEC+ regarding quotas on its members, compliance or non-compliance with quotas agreed upon by OPEC+ members and other countries, and weather. Many of the factors that can cause volatility have been, and may continue to be, affected by the impacts of the COVID-19 pandemic. 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, regulatory compliance costs and other local market factors. Natural gas prices in North America are affected by, among other things, supply and demand, inventory levels, weather and 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.

Wide differentials 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.

Commodity prices could be materially and adversely affected by the outbreak of epidemics, pandemics and other public health crises in geographic areas in which Suncor has operations, suppliers, customers or employees, including the COVID-19 pandemic and the ongoing uncertainty as to the extent and duration of the pandemic, as well as uncertainty surrounding new variations or mutations of the COVID-19 virus. Actions that have and may be taken by governmental authorities in response to the ongoing COVID-19 pandemic have resulted, and may continue to result in, among other things, increased volatility in commodity prices. In particular, the COVID-19 pandemic has resulted in, and may continue to result in, a reduction in the demand for, and prices of, commodities that are closely linked to Suncor's financial performance, including crude oil, refined petroleum products (such as jet fuel and gasoline), natural gas and electricity, and also increases the risk that storage for crude oil and refined petroleum products could reach capacity in certain geographic locations in which we operate. While vaccines are being distributed, there is uncertainty as to the timing, level of adoption, duration of efficacy and effectiveness of vaccines against current or future variants or mutations. This continues the risk and uncertainty as to the extent and duration of the COVID-19 pandemic and the resultant impact on commodity demand and prices. A prolonged period of decreased demand for, and prices of, these commodities, and any applicable storage constraints, could also result in us voluntarily curtailing or shutting in production and a decrease in our refined product volumes and refinery utilization rates. Additionally, commodity prices could remain under pressure for a prolonged period. This could result in reduced utilization and/or the

suspension of operations at certain of our facilities, buyers of our products declaring force majeure or bankruptcy, the unavailability of storage, and disruptions of pipeline and other transportation systems for our products, which would further negatively impact Suncor's production or refined product volumes, and could have a material adverse effect on Suncor's business, financial condition, reserves and results of operations.

Carbon Risk

Public support for climate change action and receptivity to alternative or 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 in support of a transition to low-carbon energy and climate change action may impose significant constraints on fossil fuel development. 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. These risks to the oil sands industry can be offset over time through the commercialization and implementation of low-carbon technologies (e.g., carbon capture, utilization and sequestration) and by increasing growth in low-carbon energies such as hydrogen, renewable fuels and power.

Changes to environmental regulations, including regulations relating to climate change, could impact the demand for the company's products or could require increased capital expenditures, operating expenses, abandonment and reclamation obligations, and distribution costs. These potential added costs may not be recoverable in the marketplace and may result in some current operations or growth projects becoming less profitable or uneconomic. Such regulatory changes could require Suncor to invest further into the development of technologies or other energy products. Such technology development or growth projects could require a significant investment of capital and resources, and any delay in or failure to identify, develop and deploy such technologies or obtain regulatory approvals for these technology projects could prevent Suncor from being able to successfully compete with other companies. More stringent GHG emissions regulations in the jurisdictions in which Suncor operates may also make it difficult for Suncor to compete with companies operating in other jurisdictions with 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 petroleum products, and could result in delayed development, stranded assets or the company being unable to further develop its hydrocarbon resources. The complexity, breadth and velocity of changes in GHG emissions regulations make it difficult to predict the potential impact to Suncor.

Suncor continues to monitor international and domestic efforts to address climate change. While GHG regulations and targets will continue to become more stringent, and while Suncor continues its efforts to reduce its GHG emissions, the absolute operational GHG emissions of the company may rise as a result of growth, mergers and acquisition activities, and changes in the operatorship of assets by Suncor or affiliates, which is particularly relevant in 2021 given that Suncor assumed operatorship of Syncrude in 2021. 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 Alberta Oil Sands Emissions Limit Act (OSELA) and the federal government's stated intention to cap and reduce emissions from the oil and gas sector by setting five-year targets to achieve net zero by 2050 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.

Greenhouse Gas Emissions and Targets

Among other sustainability goals, Suncor has set a strategic objective of net-zero emissions by 2050 and a target to reduce GHG emissions through our value chain by 10 megatonnes by 2030. Our ability to deliver GHG emissions reductions 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, development and deployment of new technologies, ability to sequester and capture carbon, investment in low-carbon power and hydrogen, as well as a 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 on the current timelines, or at all.

In addition, achieving our GHG emissions reduction targets 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, and these differences may be material. In addition, while the intent is to improve efficiency and increase the offering of low-carbon energy, 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 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.

Environmental Compliance

Tailings Management and Water Release

Each oil sands mine is required under the Alberta Energy Regulator's 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 Mine Financial Security Program (MFSP). The full impact of the Tailings Management Framework (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 and reclamation, 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.

The five-year review for the TMF is planned for 2022, which will have the potential to significantly impact progress on fluid tailings management and water release, as well as all associated aspects of TMF implementation, such as pit lakes, closure and reclamation, and the MFSP. The Alberta government has also been working to update the provincial water release policy tools and the updates are expected to be completed in 2023. In addition, work being done to develop the Federal Oil Sands Mind Effluent Regulation (OSMER) is ongoing with Environment and Climate Change Canada. If implemented, OSMER is expected to assist companies with returning water to the Athabasca River.

The review of the TMF may result in changes to the TMF that are adverse to Suncor. In addition, there can be no assurances that the provincial water release policy tools or OSMER will be updated or implemented, as the case may be, in accordance with expected timelines, if at all, or that if updated or implemented, they will permit Suncor to release water to the environment as required to support successful closure and reclamation.

In order to support successful closure and reclamation, Suncor supports an integrated water management approach for effective operations, successful reclamation and closure, and positive environmental outcomes. The inability to release sufficient water to the environment continues to result in an increase to both water quality concerns and water containment concerns at Suncor mine sites, which impacts current operations and reclamation and closure planning. Suncor believes that 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. The absence of an effective regulatory framework in this area could impact operations and 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

The implementation of, and compliance with, the terms of the Alberta's Land-Use Framework through the Lower Athabasca Regional Plan (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, and/or any updates or changes to the LARP, could have a material adverse effect on Suncor's business, financial condition, reserves and results of operations.

Alberta Environment and Parks Water Licences

Suncor currently relies on water obtained under licences from Alberta Environment and Parks 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, any changes or expansions 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.

Commerce City Refinery Water Permit

The Commerce City refinery's water discharge permit is currently subject to a renewal process. New and additional proposed requirements, including those related to per- and polyfluoroalkyl substances, could have a material adverse effect on Suncor's business, financial condition and results of operations.

Biodiversity

Species at risk exist in the areas where Suncor owns and operates its leases. For example, 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 through sub-regional planning. Suncor has existing, planned and potential future projects within caribou ranges in Alberta. The development and implementation of sub-regional plans in these areas may have an impact on the pace and amount of development in these areas and could potentially increase costs due to restoration or offsetting requirements, which could have a material adverse effect on Suncor's business, financial condition, reserves and results of operations.

Pursuant to the Alberta Wetland Policy, development in wetland areas may be obligated to avoid wetlands or mitigate the development's effects on wetlands. 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.

Air and Water Quality Management

A number of Canadian federal, provincial and U.S. federal and state air and water quality regulations and frameworks are in place currently and being developed, changed and/or implemented, which could have an impact on the company's existing operations and planned projects including by, among other things, 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.

Market Access

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 oil, 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. In order to secure future

market access, financial commitments could be made for projects that do not proceed. 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, 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 poor or substandard 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, among others, oil spills, gaseous leaks or a release of deleterious substances, loss of tailings dam integrity, 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 cyberattacks.

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.

Suncor is also subject to risks relating to the health and safety of our people, as well as the potential for a slowdown or temporary suspension of our operations in locations impacted by an outbreak such as the COVID-19 pandemic. Such a suspension in operations could also be mandated by governmental authorities in response to the COVID-19 pandemic. This could negatively impact Suncor's production or refined product volumes and refinery utilization rates for a sustained period of time, all of 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, 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 Policy

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 such as the mandatory production curtailments imposed by the Government of Alberta in 2019 and 2020), environmental protection, water, wildlife, fish, air quality, 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 environmental, health and safety 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 (temporarily or permanently), 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 certain projects, including 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, government intervention, environmental impact assessments and public hearings 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, impacts to production, reputational damage 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 the revocation of existing approvals or permits by the government 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.

Digital and Cybersecurity

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 cybersecurity 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. 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 cyberattack to, or breach of, its information technology and infrastructure.

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, 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.

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 and may result in property damage. Outcomes of such incidents 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 and E&P businesses, 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.

Portfolio Development and Execution

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

Portfolio 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.

Portfolio development and execution can also be impacted by, among other things, the effect of changing government regulations 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 complexity and diversity of Suncor's portfolio, including joint venture assets; the accuracy of project cost and schedule estimates; 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; 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 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

To achieve its business objectives, Suncor 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 it may negatively impact the company should there be inadequate consideration of the cumulative impacts of prior and parallel initiatives on people, processes and systems. There is a risk that measures undertaken to achieve 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.

Skills, Resource Shortage and Reliance on Key Personnel

The successful operation of Suncor's businesses 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 and retaining the skilled labour in certain talent segments for current and future operations. Although Suncor has maintained a healthy overall attrition rate over the last decade, Suncor sees acute supply-demand gap potential in some critical talent segments. The labour market is also in flux, which combined with the challenges recruiting to our industry and post-pandemic trend of burnout and employees reassessing their careers, increases the potential risk in attrition and the need for targeted talent remains a risk to be managed. The increasing age of the company's existing workforce, and changing skillset requirements as technology continues to evolve, add 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 or due to supply chain disruptions related to the COVID-19 pandemic. 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 Suncor's business, financial condition, reserves and results of operations. 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 and Fort Hills), all of the company's refineries and the majority of the company's terminal and distribution operations and certain of the company's E&P operations are represented by labour unions or employee associations. Approximately 25% of the company's employees were covered by collective agreements at the end of 2021. Negotiations for four collective agreements will take place in 2022. Any work interruptions involving the company's employees (including as a result of a strike, lockout or pandemic), 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.

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 and arrangements where Suncor operates assets in which other entities have 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 and operating expenditure 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

Access to Capital

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, if needed, 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. Investors and stakeholders increasingly compare companies based on climate-related performance. Failure to achieve the company's net-zero and GHG emissions reduction targets and goals, or a perception among financial institutions and investors that such targets and goals are insufficient, could adversely affect the company's reputation and ability to attract capital. The company's ability to access capital may also be adversely affected in the event that financial institutions, investors, rating agencies and/or lenders adopt more restrictive decarbonization policies. The COVID-19 pandemic had a significant impact on global capital markets and the availability of liquidity. While access to capital has returned to pre-pandemic levels, the disruption and volatility in global capital markets may re-occur. 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 nor its bylaws 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, and the level of indebtedness relative to the company's ability to generate cash flow, 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 applicable 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 some commodity sales or purchase transactions or those 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.

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, unfavourable movements in commodity prices, interest rates or foreign exchange that could result in a financial or opportunity loss to the company; a lack of counterparties, due to market conditions or other circumstances that could leave the company unable to liquidate or offset a position, or unable to do so at or near the previous market price; and counterparty default risk.

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 2021 audited Consolidated Financial Statements are presented in Canadian dollars. 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, while the majority of Suncor's expenditures are realized in Canadian dollars. Suncor also has assets and liabilities, including approximately 60% of the company's debt, that are denominated in U.S. dollars and translated to Suncor's reporting currency (Canadian dollars) at each balance sheet date. 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, 2021, the Canadian dollar strengthened in relation to the U.S. dollar to $0.79 from $0.78 at the start of 2021. 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, which are off-setting exposures to some degree. Suncor may also be exposed to higher interest rates 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 if derivative instruments are used to manage the debt portfolio. Unfavourable changes in interest rates could have a material adverse effect on Suncor's business, financial condition and results of operations.

Royalties and Taxes

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

Royalties can be impacted by changes in crude oil and natural gas pricing, production volumes, sales volumes, and capital and operating costs, by changes to existing legislation or production sharing contracts, 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, 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 prevailing business environment, 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, 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, terrorism, war, insurrection, and geopolitical and other political risks; increases in taxes and government royalties; compliance with existing and emerging anti-corruption laws, including the *Corruption of Foreign Public Officials Act* (Canada), the *Foreign Corrupt Practices Act* (United States), and *Bribery Act* (United Kingdom); 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.

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 increased in recent years, and the Canadian federal government and the provincial government in Alberta have committed to renew their relationships with the Indigenous Peoples of Canada. In particular, the federal government has stated it fully supports the United Nations Declaration on the Rights of Indigenous Peoples (the Declaration). On December 3, 2020, the federal government introduced Bill C-15, *An Act respecting the United Nations Declaration on the Rights of Indigenous Peoples* (Bill C-15), as a means of adopting the Declaration into Canadian law while stating that the legislative framework will "ensure sustained and continued efforts to uphold the rights of Indigenous Peoples now and in the future." On June 21, 2021, Bill C-15 received Royal Assent. For its part, Suncor stated support for Bill C-15. At the same time, Suncor also expressed a desire for the government to clarify the ambiguity around Bill C-15 and to provide clear guidelines. Given Bill C-15's recent adoption, it is unknown how Bill C-15 will ultimately be implemented and interpreted as a part of Canadian law, and it therefore also remains unclear what its corresponding impact will be on the Crown's duty to consult with Indigenous Peoples.

At this point Suncor is unable to assess the effect, if any, that any such land claims, consultation requirements with Indigenous Peoples or the implementation of Bill C-15 into Canadian law may have on Suncor's business; however, the impact could have a material adverse effect on Suncor's business, financial condition, reserves and results of operations.

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.

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.

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11. OTHER ITEMS

Control Environment

Based on their evaluation as of December 31, 2021, 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, 2021, 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, 2021, 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, 2021, 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, 2021.

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 February 2, 2022. For further details and advisories regarding Suncor's 2022 corporate guidance, see www.suncor.com/guidance.

12. ADVISORIES

Non-GAAP Financial Measures

Certain financial measures in this MD&A – namely adjusted operating earnings (loss), adjusted funds from (used in) operations, measures contained in ROCE and ROCE excluding impairments, price realizations, free funds flow, discretionary free funds flow (deficit), Oil Sands operations cash operating costs, Fort Hills cash operating costs, Syncrude cash operating costs, refining and marketing margin, refining operating expense, net debt, total debt, LIFO inventory valuation methodology and related per share or per barrel amounts or metrics that contain such measures – 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 financial measures are calculated and disclosed on a consistent basis from period to period. Specific adjusting items may only be relevant in certain periods.

Beginning in the fourth quarter of 2021, the company changed the label of operating earnings (loss) and funds from (used in) operations to adjusted operating earnings (loss) and adjusted funds from (used in) operations, respectively, to better distinguish the non-GAAP financial measures from the comparable GAAP measures and better reflect the purpose of the measures. The composition of the measures remains unchanged and therefore no prior periods were restated.

(a) Adjusted Operating Earnings (Loss)

Adjusted 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 adjusted operating earnings (loss) to evaluate operating performance because management believes it provides better comparability between periods. For the years ended December 31, 2021, December 31, 2020, and December 31, 2019, consolidated adjusted operating earnings (loss) are reconciled to net earnings (loss) in the Financial Information section of this MD&A and adjusted operating earnings (loss) for each segment are reconciled to net earnings (loss) in the Segment Results and Analysis section of this MD&A. Adjusted operating earnings (loss) for the three months ended December 31, 2021, and December 31, 2020, are reconciled to net earnings (loss) below.

(b) Bridge Analyses of Adjusted Operating Earnings (Loss)

Throughout this MD&A, the company presents charts that illustrate the change in adjusted operating earnings (loss) from the comparative period through key variance factors. These factors are analyzed in the Adjusted Operating Earnings (Loss) narratives following the bridge analyses in particular sections of this MD&A. These bridge analyses are presented because management uses this presentation to evaluate performance.

- The factor for Sales Volumes and Mix is calculated based on sales volumes and mix for the Oil Sands and E&P segments and throughput volumes for the R&M 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, and upstream marketing and logistics. Also included are refining and marketing margins, other operating revenue, 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, and downstream short-term commodity risk management activities.
- 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 adjusted operating earnings (loss) adjustments, changes in statutory income tax rates, and other income tax adjustments.

- The factor for DD&A and Exploration Expense includes depreciation, depletion and amortization expense, and exploration expense.

(c) Return on Capital Employed (ROCE) and ROCE Excluding Impairments

ROCE is a non-GAAP financial measure that management uses to analyze operating performance and the efficiency of Suncor's capital allocation process. ROCE is calculated using the non-GAAP financial measures adjusted net earnings and average capital employed. Adjusted net earnings is calculated by taking net earnings (loss) and adjusting after-tax amounts for unrealized foreign exchange on U.S. dollar denominated debt and net interest expense. 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.

Year ended December 31 ($ millions, except as noted)		**2021**	2020	2019
Adjustments to net earnings (loss)				
Net earnings (loss)		**4 119**	(4 319)	2 899
(Deduct) add after-tax amounts for:				
Unrealized foreign exchange gain on U.S. dollar denominated debt		**(101)**	(286)	(590)
Net interest expense		**645**	698	638
Adjusted net earnings (loss) (1)	A	**4 663**	(3 907)	2 947
Capital employed – beginning of twelve-month period				
Net debt(2)		**19 814**	16 010	15 129
Shareholders' equity		**35 757**	42 042	44 005
		55 571	58 052	59 134
Capital employed – end of twelve-month period				
Net debt(2)		**16 149**	19 814	16 010
Shareholders' equity		**36 614**	35 757	42 042
		52 763	55 571	58 052
Average capital employed	B	**54 069**	56 239	60 402
ROCE (%)(3)	A/B	**8.6**	(6.9)	4.9

(1) Total before-tax impact of adjustments is $738 million for the twelve months ended December 31, 2021, $618 million for the twelve months ended December 31, 2020, and $250 million for the twelve months ended December 31, 2019.
(2) Net debt is a non-GAAP financial measure.
(3) ROCE would have been 8.2% for the twelve months ended December 31, 2021, excluding the impact of the impairment reversal of $221 million ($168 million after-tax) in the third quarter of 2021. ROCE would have been (2.9%) for the twelve months ended December 31, 2020, excluding the impact of impairments of $559 million ($423 million after-tax) in the fourth quarter of 2020 and $1.821 billion ($1.376 billion after-tax) and $560 million ($422 million after-tax) in the first quarter of 2020. ROCE would have been 10.0% for the twelve months ended December 31, 2019, excluding the impact of impairments of $3.716 billion ($2.803 billion after-tax) and $521 million ($393 million after-tax) in the fourth quarter of 2019.

(d) Adjusted Funds from (Used in) Operations

Adjusted funds from (used in) operations is a non-GAAP financial measure that adjusts a GAAP measure – cash flow provided by 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 be impacted by, among other factors, the timing of offshore feedstock purchases and payments for commodity and income taxes, the timing of cash flows related to accounts receivable and accounts payable, and changes in inventory that management believes reduces comparability between periods.

	Oil Sands			Exploration and Production			Refining and Marketing		
Year ended December 31 ($ millions)	**2021**	2020	2019	**2021**	2020	2019	**2021**	2020	2019
Net earnings (loss)	**2 147**	(3 796)	(427)	**1 285**	(832)	1 005	**2 178**	866	3 000
Adjustments for:									
Depreciation, depletion, amortization and impairment	**4 585**	6 430	8 170	**324**	2 147	1 505	**853**	867	823
Deferred income taxes	**(51)**	(797)	(1 565)	**33**	(321)	(215)	**113**	(24)	(49)
Accretion	**240**	224	221	**58**	48	43	**6**	6	6
Unrealized foreign exchange gain on U.S. dollar denominated debt	**—**	—	—	**—**	—	—	**—**	—	—
Change in fair value of financial instruments and trading inventory	**(66)**	81	21	**3**	(17)	16	**50**	44	70
(Gain) loss on disposal of assets	**(4)**	(1)	(14)	**(227)**	—	(228)	**(19)**	(24)	(11)
Loss on extinguishment of long-term debt	**—**	—	—	**—**	—	—	**—**	—	—
Share-based compensation	**61**	(59)	16	**5**	(9)	—	**34**	(36)	3
Exploration expenses	**—**	—	—	**—**	80	66	**—**	—	—
Settlement of decommissioning and restoration liabilities	**(245)**	(212)	(413)	**(1)**	(7)	(32)	**(17)**	(12)	(19)
Other	**179**	116	52	**(2)**	(35)	(17)	**57**	21	40
Adjusted funds from (used in) operations	**6 846**	1 986	6 061	**1 478**	1 054	2 143	**3 255**	1 708	3 863
Change in non-cash working capital									
Cash flow provided by operating activities									

	Corporate and Eliminations			Total		
Year ended December 31 ($ millions)	**2021**	2020	2019	**2021**	2020	2019
Net earnings (loss)	**(1 491)**	(557)	(679)	**4 119**	(4 319)	2 899
Adjustments for:						
Depreciation, depletion, amortization and impairment	**88**	82	74	**5 850**	9 526	10 572
Deferred income taxes	**(39)**	23	(89)	**56**	(1 119)	(1 918)
Accretion	**—**	—	—	**304**	278	270
Unrealized foreign exchange gain on U.S. dollar denominated debt	**(113)**	(312)	(624)	**(113)**	(312)	(624)
Change in fair value of financial instruments and trading inventory	**—**	—	—	**(13)**	108	107
(Gain) loss on disposal of assets	**(7)**	9	—	**(257)**	(16)	(253)
Loss on extinguishment of long-term debt	**80**	—	—	**80**	—	—
Share-based compensation	**105**	(134)	25	**205**	(238)	44
Exploration expenses	**—**	—	—	**—**	80	66
Settlement of decommissioning and restoration liabilities	**—**	—	—	**(263)**	(231)	(464)
Other	**55**	17	44	**289**	119	119
Adjusted funds from (used in) operations	**(1 322)**	(872)	(1 249)	**10 257**	3 876	10 818
Change in in non-cash working capital				**1 507**	(1 201)	(397)
Cash flow provided by operating activities				**11 764**	2 675	10 421

(e) Free Funds Flow and Discretionary Free Funds Flow (Deficit)

Free funds flow is a non-GAAP financial measure that is calculated by taking adjusted funds from operations and subtracting capital expenditures, including capitalized interest. Discretionary free funds flow (deficit) is a non-GAAP financial measure that is calculated by taking adjusted funds from operations and subtracting asset sustainment and maintenance capital, inclusive of associated capitalized interest, and dividends. Both free funds flow and discretionary free funds flow (deficit) reflect cash available for increasing distributions to shareholders and to fund growth investments. Management uses free funds flow and discretionary free funds flow (deficit) to measure the capacity of the company to increase returns to shareholders and to grow Suncor's business. The following is a reconciliation of discretionary free funds flow for Suncor's last three years of operations.

($ millions)	**2021**	2020	2019
Cash flow provided by operating activities	**11 764**	2 675	10 421
Deduct (add) change in non-cash working capital	**1 507**	(1 201)	(397)
Adjusted funds from operations	**10 257**	3 876	10 818
Asset sustaining and maintenance capital and dividends (1)	**(4 667)**	(4 104)	(5 904)
Discretionary free funds flow (deficit)	**5 590**	(228)	4 914

(1) Includes capitalized interest on sustaining capital of $60 million in 2021, $46 million in 2020 and $63 million in 2019.

(f) Oil Sands Operations, Fort Hills and Syncrude Cash Operating Costs

Cash operating costs are calculated by adjusting Oil Sands segment OS&G expense for i) non-production costs that management believes do not relate to production performance, including, but not limited to, share-based compensation adjustments, CEWS, COVID-19 related costs and safe-mode costs, research costs and the expense recorded as part of a non-monetary arrangement involving a third-party processor; ii) revenues associated with excess capacity, including excess power generated and sold that is recorded in operating revenue; iii) project startup costs; and iv) the impacts of changes in inventory levels and valuation, such that the company is able to present cost information based on production volumes. Oil Sands operations and Syncrude production volumes include production of diesel that is internally consumed and feedstock transfers between assets through the interconnecting pipelines. Beginning in 2020, the company revised the methodology for calculating Syncrude cash operating costs to better align with the Oil Sands operations and Fort Hills cash operating costs methodology. Prior period Syncrude cash operating costs had previously included future development costs and have been restated to exclude these costs. 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.

(g) Refining and Marketing Gross Margin and Refining Operating Expense

Refining and marketing gross margins and refining operating expense are non-GAAP financial measures. Refining and marketing gross margin, on a FIFO basis, is calculated by adjusting R&M segment operating revenue, other income and purchases of crude oil and products (all of which are GAAP measures) for intersegment marketing fees recorded in intersegment revenues and the impact of inventory write-downs recorded in purchases of crude oil and products. Refining and marketing gross margin, on a LIFO basis, is further adjusted for the impacts of FIFO inventory valuation recorded in purchases of crude oil and products and short-term risk management activities recorded in other income (loss). 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 ii) non-refining costs that management believes do not relate to the production of refined products, including, but not limited to, CEWS, share-based compensation and enterprise shared service allocations. Management uses refining and marketing gross margin and refining operating expense to measure operating performance on a production barrel basis.

Year ended December 31 ($ millions, except as noted)	**2021**	2020	2019
Refining and marketing gross margin reconciliation			
Operating revenues	**22 915**	15 272	22 304
Purchases of crude oil and products	**(16 807)**	(11 243)	(15 296)
	6 108	4 029	7 008
Other (loss) income	**(50)**	48	75
Non-refining and marketing margin	**(54)**	(57)	(60)
Refining and marketing gross margin – FIFO	**6 004**	4 020	7 023
Refinery production(1) (mbbls)	**162 862**	158 991	173 705
Refining and marketing gross margin – FIFO (2) ($/bbl)	**36.85**	25.30	40.45
FIFO and short-term risk management activities adjustment	**(972)**	532	(628)
Refining and marketing gross margin – LIFO	**5 032**	4 552	6 395
Refining and marketing gross margin – LIFO (2) ($/bbl)	**30.90**	28.65	36.80
Refining operating expense reconciliation			
Operating, selling and general expense (3)	**2 019**	1 759	2 035
Non-refining costs(3)	**(1 051)**	(885)	(1 108)
Refining operating expense	**968**	874	927
Refinery production(1)	**162 862**	158 991	173 705
Refining operating expense ($/bbl)	**5.95**	5.50	5.35

(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.

(2) Beginning in 2020, refining and marketing gross margins have been revised to better reflect the refining, product supply and rack forward businesses. Prior periods have been restated to reflect this change.

(3) Prior period amounts of OS&G have been reclassified to align with the current year presentation of transportation and distribution expense. This reclassification had no effect on the refining operating expense.

(h) Impact of First-in, First-out (FIFO) Inventory Valuation on Refining and Marketing Net Earnings

GAAP requires the use of a FIFO inventory valuation methodology. For Suncor, this results in a disconnect between the sales prices for refined products, which reflect 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. This lag between purchase and sale can be anywhere from several weeks to several months, and is influenced by the time to receive crude after purchase (which can be several weeks for foreign offshore crude purchases), regional crude inventory levels, the completion of refining processes, transportation time to distribution channels and regional refined product inventory levels.

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) Net Debt and Total Debt

Net debt and total debt are non-GAAP financial measures that management uses to analyze the financial condition of the company. 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 (all of which are GAAP measures). Net debt is equal to total debt less cash and cash equivalents (a GAAP measure).

At December 31 ($ millions, except as noted)	**2021**	2020	2019
Short-term debt	**1 284**	3 566	2 155
Current portion of long-term debt	**231**	1 413	—
Current portion of long-term lease liabilities	**310**	272	310
Long-term debt	**13 989**	13 812	12 884
Long-term lease liabilities	**2 540**	2 636	2 621
Total debt	**18 354**	21 699	17 970
Less: Cash and cash equivalents	**2 205**	1 885	1 960
Net debt	**16 149**	19 814	16 010
Shareholders' equity	**36 614**	35 757	42 042
Total debt plus shareholders' equity	**54 968**	57 456	60 012
Total debt to total debt plus shareholders' equity (%)	**33.4**	37.8	29.9
Net debt to net debt plus shareholders' equity (%)	**30.6**	35.7	27.6
Net debt to net debt plus shareholders' equity – excluding leases (%)	**26.6**	32.1	23.7

(j) Price Realizations

Price realizations are a non-GAAP measure used by management to measure profitability. Oil Sands price realizations are presented on a crude product basis and are derived from the Oil Sands segmented statement of net earnings (loss), after adjusting for items not directly attributable to the revenues associated with production. E&P price realizations are presented on an asset location basis and are derived from the E&P segmented statement of net earnings (loss), after adjusting for other E&P assets, such as Libya, for which price realizations are not provided.

Oil Sands Price Realizations

For the year ended	**December 31, 2021**				December 31, 2020			
($ millions, except as noted)	**Bitumen**	**SCO and Diesel**	**Crude sales basket**	**Oil Sands Segment**	Bitumen	SCO and Diesel	Crude sales basket	Oil Sands Segment
Operating revenues, net of royalties	**5 092**	**13 305**	**18 397**	**18 397**	2 024	8 498	10 522	10 522
Add: Royalties	**376**	**1 147**	**1 523**	**1 523**	19	76	95	95
Operating revenues	**5 468**	**14 452**	**19 920**	**19 920**	2 043	8 574	10 617	10 617
Other (loss) income	**(56)**	**62**	**6**	**6**	21	277	298	298
Purchases of crude oil and products	**(1 231)**	**(213)**	**(1 444)**	**(1 444)**	(702)	(142)	(844)	(844)
Gross realization adjustment (1)	**(210)**	**(325)**	**(535)**		(54)	(458)	(512)	
Gross realizations	**3 971**	**13 976**	**17 947**		1 308	8 251	9 559	
Transportation and distribution	**(359)**	**(767)**	**(1 126)**	**(1 126)**	(476)	(747)	(1 223)	(1 223)
Transportation and distribution adjustment (2)	**—**	**—**	**—**		197	—	197	
Net transportation and distribution	**(359)**	**(767)**	**(1 126)**		(279)	(747)	(1 026)	
Price realization	**3 612**	**13 209**	**16 821**		1 029	7 504	8 533	
Sales volumes (mbbls)	**67 094**	**169 983**	**237 077**		45 980	171 211	217 191	
Price realization per barrel	**53.80**	**77.73**	**70.96**		22.37	43.83	39.29	

For the year ended	December 31, 2019			
($ millions, except as noted)	Bitumen	SCO and Diesel	Crude sales basket	Oil Sands Segment
Operating revenues, net of royalties	4 656	12 774	17 430	17 430
Add: Royalties	124	793	917	917
Operating revenues	4 780	13 567	18 347	18 347
Other (loss) income	(38)	210	172	172
Purchases of crude oil and products	(1 164)	(243)	(1 407)	(1 407)
Gross realization adjustment (1)	(14)	(219)	(233)	
Gross realizations	3 564	13 315	16 879	
Transportation and distribution	(449)	(844)	(1 293)	(1 293)
Transportation and distribution adjustment (2)	15	7	22	
Net transportation and distribution	(434)	(837)	(1 271)	
Price realization	3 130	12 478	15 608	
Sales volumes (mbbls)	68 430	176 494	244 924	
Price realization per barrel	45.71	70.68	63.70	

(1) Reflects the items not directly attributed to revenues received from the sale of proprietary crude and net non-proprietary activity at its deemed point of sale.
(2) Reflects adjustments for expenses or credits not directly related to the transportation of the crude product to its deemed point of sale.

E&P Price Realizations

For the year ended	December 31, 2021				December 31, 2020			
($ millions, except as noted)	**E&P International**	**E&P Canada**	**Other(1)**	**E&P Segment**	E&P International	E&P Canada	Other(1)	E&P Segment
Operating revenues, net of royalties	**815**	**1 447**	**238**	**2 500**	809	1 058	(111)	1 756
Add: Royalties	**—**	**237**	**241**	**478**	—	94	49	143
Operating revenues	**815**	**1 684**	**479**	**2 978**	809	1 152	(62)	1 899
Transportation and distribution	**(25)**	**(44)**	**(43)**	**(112)**	(34)	(65)	(1)	(100)
Price realization	**790**	**1 640**	**436**		775	1 087	(63)	
Sales volumes (mbbls)	**9 616**	**19 386**			15 406	21 879		
Price realization per barrel	**82.16**	**84.70**			50.28	49.69		

For the year ended	December 31, 2019			
($ millions, except as noted)	E&P International	E&P Canada	Other(1)	E&P Segment
Operating revenues, net of royalties	1 309	1 621	140	3 070
Add: Royalties	—	302	303	605
Operating revenues	1 309	1 923	443	3 675
Transportation and distribution	(35)	(39)	(6)	(80)
Price realization	1 274	1 884	437	
Sales volumes (mbbls)	15 650	22 190		
Price realization per barrel	81.22	84.86		

(1) Reflects other E&P assets, such as Libya, for which price realizations are not provided.

(k) Adjusted Operating Earnings (Loss)(1) Reconciliations – Fourth Quarter 2021 and 2020

For the quarter ended December 31	Oil Sands		Exploration and Production		Refining and Marketing		Corporate and Eliminations		Total	
($ millions)	**2021**	2020	**2021**	2020	**2021**	2020	**2021**	2020	**2021**	2020
Net earnings (loss)	**896**	(293)	**465**	(379)	**450**	268	**(258)**	236	**1 553**	(168)
Unrealized foreign exchange gain on U.S. dollar denominated debt	**—**	—	**—**	—	**—**	—	**(21)**	(539)	**(21)**	(539)
Unrealized loss (gain) on risk management activities(1)	**2**	21	**—**	—	**(13)**	12	**—**	—	**(11)**	33
Gain on significant disposal(2)	**—**	—	**(227)**	—	**—**	—	**—**	—	**(227)**	—
Asset Impairments(3)	**—**	—	**—**	423	**—**	—	**—**	—	**—**	423
Provision for pipeline project(4)	**—**	142	**—**	—	**—**	—	**—**	—	**—**	142
Adjusted operating earnings (loss)	**898**	(130)	**238**	44	**437**	280	**(279)**	(303)	**1 294**	(109)

(1) Beginning in 2021, the company revised its calculation of adjusted operating earnings (loss), a non-GAAP financial measure, to exclude unrealized (gains) losses on derivative financial instruments that are recorded at fair value in other income (loss) to better align the earnings impact of the activity with the underlying items being risk-managed. Prior period comparatives have been restated to reflect this change.

(2) In the fourth quarter of 2021, the company completed the sale of its 26.69% working interest in the Golden Eagle Area Development, in the E&P segment, for proceeds of $227 million ($227 million after-tax) net of closing adjustments and other closing costs, in addition to future contingent consideration of up to US$50 million.

(3) In the fourth quarter of 2020, the company recorded non-cash impairment charges of $559 million ($423 million after-tax) against its share of the White Rose assets as a result of the high degree of uncertainty surrounding the future of the West White Rose Project.

(4) In the fourth quarter of 2020, the company recorded a provision to transportation expense for $186 million ($142 million after-tax) related to the Keystone XL pipeline project.

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(I) Adjusted Funds from Operations Reconciliations – Fourth Quarter 2021 and 2020

For the quarter ended December 31 ($ millions)	Oil Sands		Exploration and Production		Refining and Marketing		Corporate and Eliminations		Total	
	2021	2020	**2021**	2020	**2021**	2020	**2021**	2020	**2021**	2020
Net earnings (loss)	**896**	(293)	**465**	(379)	**450**	268	**(258)**	236	**1 553**	(168)
Adjustments for:										
Depreciation, depletion, amortization and impairment	**1 237**	1 058	**129**	835	**243**	207	**21**	20	**1 630**	2 120
Deferred income taxes	**(11)**	(154)	**(2)**	(160)	**45**	(53)	**(28)**	43	**4**	(324)
Accretion	**61**	55	**15**	13	**1**	1	**—**	—	**77**	69
Unrealized foreign exchange gain on U.S. dollar denominated debt	**—**	—	**—**	—	**—**	—	**(25)**	(602)	**(25)**	(602)
Change in fair value of financial instruments and trading inventory	**8**	49	**42**	5	**—**	(9)	**—**	—	**50**	45
(Gain) loss on disposal of assets	**(4)**	1	**(227)**	—	**(1)**	(18)	**—**	9	**(232)**	(8)
Share-based compensation	**36**	25	**4**	3	**21**	15	**64**	52	**125**	95
Settlement of decommissioning and restoration liabilities	**(71)**	(41)	**1**	—	**(6)**	(7)	**—**	—	**(76)**	(48)
Other	**23**	29	**(2)**	(5)	**12**	11	**5**	7	**38**	42
Adjusted funds from (used in) operations	**2 175**	729	**425**	312	**765**	415	**(221)**	(235)	**3 144**	1 221
Change in non-cash working capital									**(529)**	(407)
Cash flow provided by operating activities									**2 615**	814

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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 estimates; the current and potential adverse impacts of the COVID-19 pandemic, including the status of the pandemic and future waves; 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, including its priority to deliver competitive and sustainable returns to shareholders and its aim to maximize shareholder returns, its plans on how to achieve this strategy, its belief that its commitment to capital discipline, its balance sheet strength and financial health provides the foundation for its capital allocation framework by supporting long-term value creation and returns to shareholders, and Suncor's belief that it is well positioned to execute on these priorities due to the company's competitive advantages: financial strength, an industry-leading long-life, low-decline oil sands reserves base, an offshore business that provides geographically diversified cash flow, a highly efficient, tightly integrated downstream business supported by competitive sales channels and its investment in sustainability, technology and innovation;*

- *Suncor's belief that its growth and development plans will be focused on highly economical projects and initiatives that are synergistic with its core capabilities and will create long-term value for the company through free funds flow growth and Suncor's belief that it will be able to execute improvement strategies at existing assets and realize structural cost savings;*

- *the belief that Suncor's broad asset base and operational flexibility will allow Suncor to optimize the production of higher-value SCO in the upstream, while its extensive logistics assets and sales channels, enhanced by its trading and marketing expertise, drives additional value as equity barrels move down the value chain and that, through this midstream and marketing network and its geographical diversity, the company is able to maximize crude production and refinery utilization by securing sales outlets while receiving global-based pricing for the majority of its production;*

- *Suncor's aim to get the most out of its assets through a focus on operational excellence and its belief that focusing on investments that generate structural reductions to its capital requirements with a continued focus on improved productivity and reliability will drive down overall cost structures and sustainment capital requirements and are expected to help it achieve maximum value for its operations;*

- *the expectation that Suncor's assumption of operatorship of the Syncrude asset will be a critical step towards greater integration, efficiencies and competitiveness across all Suncor-operated assets in the region, further strengthening the company's regional oil sands advantage, the expectation that Suncor assuming operatorship will capture increased value for the owners through improved operational performance, efficiency and competitiveness and expectations regarding the realization of $100 million of annual gross synergies for the joint venture owners in 2022, with an additional $200 million expected to be realized through 2023–2024;*

- *statements about Suncor's strategic objective to be a net-zero GHG emissions company by 2050 and its near-term GHG emissions reduction goal, including Suncor's aim to substantially contribute to society's net-zero goals by reducing emissions across its base business, growing its low-emissions energy business and working with others to reduce emissions;*

- *Suncor's belief that its investments in the energy expansion will complement its existing core capabilities: increasing its low-carbon power generation, expanding into clean hydrogen production and growing its existing renewable liquid fuels business, and that unleashing the full potential of its people and technology will be critical in achieving its environmental, operational and financial goals;*

- *Suncor's expectation that it will operate the Fort Hills asset at average utilization rates of 90% throughout 2022;*

- *expectations regarding the acquisition, through Astisiy, of an equity interest in the Northern Courier Pipeline, including that it will provide the eight Indigenous communities with reliable income for decades;*

- *Suncor's expectations with respect to the Terra Nova project, including with respect to the Asset Life Extension Project that is expected to extend production life by approximately a decade, the expectation that there will be a safe and reliable return to operations before the end of 2022 and the timing of maintenance work on the Floating, Production, Storage and Offloading facility;*

- *statements about Buzzard Phase 2, including the expectation that it will extend the production life of the existing field and reach its peak production of 12,000 boe/d gross (approximately 3,500 boe/d net to Suncor) in 2022;*

- *statements regarding the Oil Sands Pathways to Net Zero alliance, including its aims, expectations regarding timing and the expected pathways the alliance will take to address GHG emissions;*

- *the aim, objectives and potential benefits of Suncor's clean energy investments, including Enerkem Inc., LanzaJet, Inc., Svante Inc. and the Varennes Carbon Recycling facility, and Suncor's belief that these investments complement Suncor's existing product mix and demonstrate Suncor's involvement in the evolving global energy expansion and are key to Suncor's emissions reduction goal;*

- *that Suncor will remain disciplined in its plans to reduce debt towards its 2025 targeted net debt range of $12–$15 billion and 2030 targets and the company's plans to allocate its annual free funds flow, after its dividend, evenly between share buybacks and debt reductions;*

- *statements about Suncor's incremental free funds flow target by 2025, including the projects that are expected to help Suncor meet this target;*

- *the expectation that capital discipline will continue to focus on asset sustainment and maintenance projects designed to maintain safe and reliable operations, as well as advancing high-value economic investment projects, and will continue to invest in projects that are economically robust, sustainably focused and technologically progressive;*

- *Suncor's expectation that it will continue to advance its digital transformation which are expected to contribute to Suncor's incremental free funds flow target and facilitate the transition to the workplace of the future, bolster operational excellence and drive additional value;*

- *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 to generate electricity that will be transmitted to Alberta's power grid and provide a lower-carbon power alternative while delivering value to Suncor and the expectation that it will be in-service between 2024* and *2025;*

- *statements about the sanctioned Forty Mile Wind Power Project, including the expectation that the project will generate significant value through sustainable power generation and retention of the generated carbon credits for utilization in Suncor's upstream business and the belief that the project will be completed and operational in late 2022, contributing to the company's incremental free funds flow and emissions reduction goals while meeting growing customer demand for lower-carbon energy;*

- *expectations for Suncor's partnership with ATCO Ltd. on a potential world-scale clean hydrogen project, including the expected benefits and timing estimates;*

- *expectations for the Oil Sands segment, including the expectation that Suncor will continue to advance incremental debottlenecks to maximize the value of the Firebag asset, which will depend on economic conditions supported by integrated well pad development and Solvent SAGD technologies, the deployment of digital mine optimization and*

AHS and the expected benefits therefrom, and the potential development opportunities that may support future in situ production, including Meadow Creek, Lewis, OSLO, Gregoire, Chard and Kirby;

- *the expectation that Suncor will remain focused on operational excellence and increasing reliability and utilization across its assets, will continue to operate in a safe, reliable manner, while optimizing production and remain committed to maximizing utilization of our upgraders to produce the highest-value barrels, which will be further enabled by optimizing transfers on the interconnecting pipelines between Suncor's Oil Sands Base and Syncrude;*

- *the expectation that the Mildred Lake Extension project will sustain Syncrude's current production levels by extending the life of the North Mine using existing extraction and upgrading facilities while minimizing the environmental impacts of building infrastructure and that the project will come online in late 2025;*

- *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, which are planned to continue in 2022;*

- *expectations for the R&M segment, including that the company will continue to pursue midstream opportunities and the anticipated benefits therefrom, the expectation that refinery throughput will return to 2019 levels, which will position the company to capture improving margins and demand, and that the R&M capital program in 2022 will be heavily weighted towards asset sustainment and maintenance activities focused on ongoing sustainment and enhancement to refinery operations and the company's plans to make economic investments in expansions of the company's retail and wholesale network; 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 turnaround at Firebag, annual coker maintenance at Oil Sands Base Upgrader 2, maintenance and turnaround at Syncrude and maintenance at Fort Hills; and*

- *planned maintenance at the Sarnia, Edmonton and Montreal refineries.*

Also:

- *economic sensitivities;*

- *Suncor's belief that its indicative 5-2-2-1 index will continue to be an appropriate measure against Suncor's actual results;*

- *the company's priority regarding returning value to shareholders and strengthening the balance sheet, and the company's ongoing ability to generate cash flow and commitment to return cash to shareholders;*

- *statements about Suncor's share repurchase program, including its belief that, depending on the trading price of its common shares and other relevant factors, purchasing its own shares represents an attractive investment opportunity and is in the best interests of the company and its shareholders, and Suncor's expectation that the decision to allocate cash to repurchase shares will not affect its long-term strategy;*

- *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 2021 capital spending program of $4.7 billion and the belief that the company will have the capital resources to fund its planned 2021 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 2022 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 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 (including as a result of demand and supply effects resulting from the COVID-19 pandemic and the actions of OPEC+); 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 2021 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.

EXHIBIT 99-4

Consent of KPMG 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 23, 2022, 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 Form F-10 (No. 333-238618) of Suncor Energy Inc.

"*KPMG LLP*"

Chartered Professional Accountants
Calgary, Canada
February 24, 2022

EXHIBIT 99-5

Consent of GLJ 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 Ltd. ("**GLJ**"):

- Reserves Assessment and Evaluation of In Situ Oil Sands Properties – Corporate Summary dated February 18, 2022;
- Reserves Assessment and Evaluation of Oil Sands Mining Properties – Corporate Summary dated February 18, 2022;
- Reserves Assessment and Evaluation of the P&NG Reserves of Suncor Energy Inc., Newfoundland Offshore Areas dated February 18, 2022;
- Reserves Assessment and Evaluation of the P&NG Reserves of Suncor Energy Inc., Norway Properties dated February 18, 2022; and
- Reserves Assessment and Evaluation of the P&NG Reserves of Suncor Energy Inc., UK Properties dated February 18, 2022,

which provide GLJ's reports on proved and probable reserves evaluations of Suncor's Canadian mining and in-situ leases, Canadian offshore conventional assets and international operations that were evaluated as at December 31, 2021.

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, 2021 (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. 333-238618) of Suncor, of our Reports;
2. Annual Report for the year ended December 31, 2021 (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 23, 2022 (the "**AIF**"), which is incorporated by reference into the following prospectuses (collectively, the "**Prospectuses**"): (i) the short form base shelf prospectus of Suncor dated May 29, 2020 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. $5,000,000,000, and (ii) the short form base shelf prospectus of Suncor dated May 29, 2020 relating to the sale and issue of medium term notes, from time to time, in the aggregate principal amount of up to CDN $5,000,000,000.

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 LTD.

"*Tim R. Freeborn*"

Tim R. Freeborn, P. Eng.
Vice-President and Chief Financial Officer

Dated: February 24, 2022
Calgary, Alberta, Canada

EXHIBIT 99-6

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.

DATE: February 24, 2022

/s/ MARK S. LITTLE

Mark S. Little
President and Chief Executive Officer

EXHIBIT 99-7

CERTIFICATION

I, Alister Cowan, certify that:

1. I have reviewed this annual report on Form 40-F of Suncor Energy Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

    (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    (c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    (d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

    (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

    (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

DATE: February 24, 2022

/s/ ALISTER COWAN

Alister Cowan
Chief Financial Officer

EXHIBIT 99-8

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,
AS ENACTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the annual report of Suncor Energy Inc. (the "Company") on Form 40-F for the fiscal year ending December 31, 2021 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 24, 2022

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, 2021 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 24, 2022

Exhibit 99.10

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, 2021 (the "2021 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 2021 Consolidated Financial Statements are attached as Exhibit 99.2 to Suncor's annual report on Form 40-F for the year ended December 31, 2021 (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 2021 Annual Information Form (the "2021 AIF"), which is attached as Exhibit 99.1 to the Form 40-F. Readers should also see Suncor's Management's Discussion and Analysis for the year ended December 31, 2021, which is attached as Exhibit 99.3 to the Form 40-F (the "2021 Management's Discussion and Analysis").

The reserves data presented herein, with an effective date of December 31, 2021, 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 2021 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. In 2021, for Suncor's Oil Sands Base mining operations, Fort Hills oil sands mining project, Syncrude oil sands mining project, and the Terra Nova offshore project, the application of constant pricing resulted in these projects being economic, compared to uneconomic in 2020 when no reserves were attributed to these properties due to the unprecedented impacts of the COVID-19 pandemic on commodity prices. In 2021, Suncor's reserves were economic utilizing both constant pricing permitted by Subpart 1200, as well as forecast pricing permitted by NI 51-101.

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 2021 Consolidated Financial Statements, the 2021 Management's Discussion and Analysis and the 2021 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)	
	2021	2020	2021	2020	2021	2020	2021	2020	2021	2020
Proved Developed										
Oil Sands	1,518	246	826	92	-	-	-	-	2,344	338
Exploration and Production	-	-	-	-	128	106	1	1	129	107
	1,518	246	826	92	128	106	1	1	2,473	445
Proved Undeveloped										
Oil Sands	868	722	398	262	-	-	-	-	1,266	984
Exploration and Production	-	-	-	-	21	38	8	8	22	39
	868	722	398	262	21	38	8	8	1,288	1,023
Proved										
Oil Sands	2,386	968	1,224	354	-	-	-	-	3,610	1,322
Exploration and Production	-	-	-	-	149	144	9	9	150	146
	2,386	968	1,224	354	149	144	9	9	3,760	1,468

Reconciliation of Net Proved Oil and Gas Reserves

(net reserves, constant prices and costs)	Balance at December 31 2019	Revisions of Previous Estimates[4]	Improved Recovery[5]	Acquisitions	Extensions and Discoveries[7]	Production	Dispositions	Balance at December 31 2020
Oil Sands								
SCO (mmbbls)	2,574	(1,438)	1	-	-	(169)	-	968
Bitumen (mmbbls)	1,532	(1,134)	1	-	-	(45)	-	354
Exploration and Production								
Crude oil[3] (mmbbls)	160	10	2	-	7	(34)	-	144
Natural gas (bcf)	11	(1)	-	-	-	(1)	-	9
Total (mmboe)	4,267	(2,563)	4	-	7	(247)	-	1,468

(net reserves, constant prices and costs)	Balance at December 31 2020	Revisions of Previous Estimates[4]	Improved Recovery[5]	Acquisitions[6]	Extensions and Discoveries[7]	Production	Dispositions[8]	Balance at December 31 2021
Oil Sands								
SCO (mmbbls)	968	1,309	1	-	274	(166)	-	2,386
Bitumen (mmbbls)	354	698	-	-	218	(46)	-	1,224
Exploration and Production								
Crude oil[3] (mmbbls)	144	34	-	4	-	(28)	(6)	149
Natural gas (bcf)	9	1	-	-	-	(1)	-	9
Total (mmboe)	1,468	2,041	1	4	492	(240)	(6)	3,760

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 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; and can be expected to be recovered through extraction equipment and infrastructure to be installed for projects that extract oil by means not involving a well.

(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. Positive revisions in 2021 are primarily due to Suncor's Oil Sands Base mining operations, Fort Hills oil sands mining project, Syncrude oil sands mining project and the Terra Nova offshore project being economic under constant pricing in 2021, compared to uneconomic in 2020 when no reserves were attributed to these properties. These revisions were partially offset by downward technical revisions at Syncrude and Fort Hills, as well as increased royalties at Firebag and Oil Sands Base resulting in lower net proved reserves.

(5) Improved recoveries relates to additions to reserves resulting from deployment of improved recovery schemes such as Steam Assisted Gravity Drainage in In Situ and waterflood in Exploration and Production.

(6) Acquisitions are due to Suncor finalizing a new ownership agreement for Terra Nova in the third quarter of 2021, which increased Suncor's working interest from 37.675% to 48%.

(7) 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. Proved undeveloped reserves associated with Suncor's MacKay River In Situ project and Syncrude Mildred Lake West project were added in 2021.

(8) Dispositions relate to Suncor completing the sale of its 26.69% working interest in the Golden Eagle Area Development early in the fourth quarter of 2021.

Capitalized Costs

($ millions)	At December 31, 2021 Oil Sands	Exploration and Production	Total	At December 31, 2020 Oil Sands	Exploration and Production	Total
Exploration and evaluation assets[1]	2,012	215	2,227	2,061	225	2,286
Oil and gas properties[2][3]	19,841	20,477	40,318	20,124	22,586	42,710
Plant and equipment[2][3]	68,009	1,018	69,027	66,875	1,054	67,929
- accumulated provision[2]	(37,971)	(15,999)	(53,970)	(35,059)	(17,424)	(52,483)
Total	51,891	5,711	57,602	54,001	6,441	60,442

(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 18 of the 2021 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 2021 Consolidated Financial Statements. Includes amounts capitalized to Property, Plant and Equipment on the Consolidated Balance Sheets of the 2021 Consolidated Financial Statements that relate to the company's right-of-use assets under IFRS 16. See note 17 of the 2021 Consolidated Financial Statements.

(3) Includes amounts capitalized to Property, Plant and Equipment on the Consolidated Balance Sheets of the 2021 Consolidated Financial Statements that relate to the company's decommissioning and restoration activities.

Costs Incurred for Property Acquisition, Exploration and Development Activities

($ millions)	Year ended December 31, 2021 Oil Sands	Exploration and Production	Total	Year Ended December 31, 2020 Oil Sands	Exploration and Production	Total
Unproved property acquisition	-	-	-	-	-	-
Proved property acquisition[1]	-	65	65	-	-	-
Exploration[2]	15	36	51	174	189	363
Development[3]	3,172	222	3,394	2,723	431	3,154
Total	3,187	323	3,510	2,897	620	3,517

(1) Proved property acquisitions are primarily due to Suncor finalizing a new ownership agreement for Terra Nova in the third quarter of 2021, which increased Suncor's working interest from 37.675% to 48%.

(2) 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 (Loss), of the 2021 Consolidated Financial Statements.

(3) Includes amounts capitalized to Property, Plant and Equipment on the Consolidated Balance Sheets of the 2021 Consolidated Financial Statements that relate to the company's decommissioning and restoration activities.

Results of Operations for Oil and Gas Producing Activities

	Year ended December 31, 2021			Year Ended December 31, 2020		
($ millions)	Oil Sands	Exploration and Production	Total	Oil Sands	Exploration and Production	Total
Operating revenues, net of royalties	18,397	2,500	20,897	10,522	1,756	12,278
Other income	6	17	23	298	54	352
	18,403	2,517	20,920	10,820	1,810	12,630
Purchases of crude oil and products	1,444	-	1,444	844	-	844
Operating, selling and general	8,056	429	8,485	7,169	476	7,645
Transportation	1,126	112	1,238	1,223	100	1,323
Depreciation, depletion, amortization and impairment	4,585	324	4,909	6,430	2,147	8,577
Exploration	12	35	47	57	129	186
Gain on disposal of assets	(4)	(227)	(231)	(1)	-	(1)
Finance expenses	359	53	412	336	47	383
Earnings (loss) before income taxes	2,825	1,791	4,616	(5,238)	(1,089)	(6,327)
Income taxes - expense (recovery)	678	506	1,184	(1,442)	(257)	(1,699)
Net earnings (loss)	2,147	1,285	3,432	(3,796)	(832)	(4,628)

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves (1)

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 average of the first-day-of-the-month prices for the twelve-month period prior to the end of the reporting period, 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 evaluator (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 (using the first-day-of-the-month prices for the twelve-month period prior to the end of the reporting period):

Year	2021 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
2021	69.22	66.56	66.94	78.39	83.66	3.41	18.38
2020	41.77	39.57	35.81	45.51	49.73	2.17	4.32

($ millions)	At December 31, 2021			At December 31, 2020		
	Oil Sands	Exploration and Production	Total	Oil Sands	Exploration and Production	Total
Future cash inflows	259,065	12,699	271,764	56,737	7,552	64,289
Future production costs	(121,138)	(3,527)	(124,665)	(28,763)	(2,388)	(31,151)
Future development costs	(56,346)	(2,537)	(58,883)	(15,115)	(2,285)	(17,400)
Future income tax expenses	(17,839)	(1,803)	(19,642)	(2,839)	(194)	(3,033)
Future net cash flows	63,742	4,832	68,574	10,020	2,685	12,705
10% Discount Factor	(32,377)	(821)	(33,198)	(5,588)	(279)	(5,867)
Standardized measure of discounted future net cash flows	31,365	4,011	35,376	4,432	2,405	6,837

Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

($ millions)	2021	2020
Standardized measure of discounted future net cash flows - beginning of year	6,837	23,277
Sales and transfers of oil and gas produced	(3,184)	(4,852)
Net changes in sales prices and operating costs related to future production	43,572	(19,761)
Net change due to extensions, discoveries and improved recovery	2,766	292
Net change due to acquisition and dispositions	201	-
Net change due to revisions in quantity estimates	(8,537)	1,355
Previously estimated development costs incurred during the period	3,692	894
Changes in estimated future development costs	(2,448)	619
Accretion of discount	717	1,681
Net change in income taxes	(8,239)	3,333
Standardized measure of discounted future net cash flows - end of year	35,376	6,837

(1) Tables may not add due to rounding.