Annual Information Form

Dated March 6, 2023

SUNCOR

Annual Information Form dated March 6, 2023

Table of Contents

1	Advisories
2	Glossary of Terms and Abbreviations
2	Common Industry Terms
4	Common Abbreviations
5	Conversion Table
6	Corporate Structure
6	Name, Address and Incorporation
6	Intercorporate Relationships
7	General Development of the Business
7	Overview
8	Three-Year History
12	Narrative Description of Suncor's Businesses
12	Oil Sands
16	Exploration and Production
19	Refining and Marketing
23	Other Suncor Businesses
24	Suncor Employees
24	Ethics, Social and Environmental Policies
26	Statement of Reserves Data and Other Oil and Gas Information
28	Oil and Gas Reserves Tables and Notes
33	Future Net Revenues Tables and Notes
39	Additional Information Relating to Reserves Data
49	Industry Conditions
61	Risk Factors
61	Dividends
62	Description of Capital Structure
64	Market for Securities
65	Directors and Executive Officers
71	Audit Committee Information
73	Legal Proceedings and Regulatory Actions
73	Interests of Management and Others in Material Transactions
73	Transfer Agent and Registrar
73	Material Contracts
73	Interests of Experts
73	Disclosure Pursuant to the Requirements of the NYSE
73	Additional Information
75	Advisory – Forward-Looking Information and Non-GAAP Financial Measures
	Schedules
A-1	Schedule "A" – Audit Committee Mandate
B-1	Schedule "B" – Suncor Energy Inc. Policy and Procedures for Pre-Approval of Audit and Non-Audit Services
C-1	Schedule "C" – Form 51-101F2 Report on Reserves Data by Independent Qualified Reserves evaluator or Auditor
D-1	Schedule "D" – Form 51-101F3 Report of Management and Directors on Reserves Data and Other Information

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 2022 audited Consolidated Financial Statements), unless the context otherwise requires. Suncor Energy Inc. has numerous direct and indirect subsidiaries, partnerships and joint arrangements (affiliates), that 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 2022 audited Consolidated Financial Statements mean Suncor's audited Consolidated Financial Statements prepared in accordance with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB), the notes thereto and the auditor's report thereon, as at and for each year in the two-year period ended December 31, 2022. References to the annual 2022 MD&A mean Suncor's Management's Discussion and Analysis for the year ended December 31, 2022, dated March 6, 2023.

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, many of which are beyond the company's control. Many of these risk factors and other assumptions related to Suncor's forward-looking statements are discussed in further detail throughout this AIF and the company's annual 2022 MD&A under the heading Risk Factors, which section is incorporated by reference herein and available on Suncor's SEDAR profile at sedar.com. Users of this information are cautioned that actual results may differ materially from those expressed or implied by the forward-looking statements contained herein. Refer to the Advisory – Forward-Looking Information and Non-GAAP Financial Measures section of this AIF for information on risk factors and the material assumptions underlying the forward-looking statements.

Information contained in or otherwise accessible through Suncor's website www.suncor.com does not form a part of this AIF and is not incorporated into this AIF by reference.

Glossary of Terms and Abbreviations

Common Industry Terms

Products

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

Wells

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

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
GHG	greenhouse gas
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 m^3 natural gas = 35.49 cubic feet
1 m^3 overburden = 1.31 cubic yards

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

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

(2) Some information in this AIF is disclosed in metric units and some in imperial units.

Corporate Structure

Name, Address and Incorporation

Suncor Energy Inc. (formerly Suncor Inc.) was originally formed by the amalgamation under the *Canada Business Corporations Act* (the CBCA) on August 22, 1979, of Sun Oil Company Limited, incorporated in 1923, and Great Canadian Oil Sands Limited, incorporated in 1953. On January 1, 1989, the company further amalgamated with a wholly owned subsidiary under the CBCA. The company amended its Articles in 1995 to move its registered office from Toronto, Ontario, to Calgary, Alberta, and again in April 1997 to adopt the name, "Suncor Energy Inc." In April 1997, May 2000, May 2002 and May 2008 the company amended its Articles to divide its issued and outstanding shares on a two-for-one basis.

Pursuant to an arrangement under the CBCA, which was completed effective August 1, 2009, Suncor amalgamated with Petro-Canada™ to form a single corporation continuing under the name "Suncor Energy Inc." On January 1, 2017, Suncor amalgamated with certain of its wholly owned subsidiaries under the CBCA.

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

Intercorporate Relationships

Suncor's material subsidiaries, held either directly or indirectly, by the company as at December 31, 2022, 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 NGLs and 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, 2022, and (ii) less than 10% of the company's consolidated revenues for the fiscal year ended December 31, 2022. In aggregate, the remaining subsidiaries accounted for less than 20% of the company's consolidated assets as at December 31, 2022, and less than 20% of the company's consolidated revenues for the fiscal year ended December 31, 2022.

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 investments in power, renewable fuels and hydrogen. Suncor also conducts energy trading activities focused principally on marketing and trading crude oil, natural gas, byproducts, refined products and power. Suncor has been recognized for its performance and transparent reporting on the Dow Jones Sustainability World Index, FTSE4Good Index and CDP. 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. This infrastructure includes utilities, energy, reclamation and storage facilities, the interconnecting pipelines between Suncor's Oil Sands Base operations and Syncrude, and the new hot bitumen transfer piping that connects Fort Hills to Oil Sands Base. Oil Sands Base also includes mining development opportunities, including interests in Base Mine Extension (100%) and Audet (100%).
  - **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 interests in 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 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. Subsequent to 2022, Suncor acquired an additional 14.65% working interest in Fort Hills from Teck Resources Limited (Teck), increasing the company's and its affiliate's total aggregate working interest to 68.76%.
- **Syncrude** refers to Suncor's 58.74% interest in the oil sands mining and upgrading operation, which the company operates.

Exploration and Production

Suncor's Exploration and Production (E&P) segment consists of offshore operations off the east coast of Canada and in the U.K. 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. Investment in the Terra Nova Floating Production, Storage and Offloading (FPSO) facility related to the Asset Life Extension (ALE) Project was substantially progressed in 2022, and the asset has returned to Canada, with a safe return to production expected in the second quarter of 2023. In the second quarter of 2022, Suncor and the joint venture owners announced the decision to restart the West White Rose Project. In connection with the decision to restart the West White Rose Project, Suncor increased its interest in the White Rose assets by 12.5% to 40% in the base project and 38.6% in the extensions. Production from the West White Rose Project is expected to commence in the first half of 2026. Suncor also holds non-operated interests in Hibernia (20% in the base project and 19.485% in the Hibernia Southern Extension Unit) and Hebron (21.034%). 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%) and the Rosebank future development project (40%), both of which are located in the U.K. sector of the North Sea. In 2022, Suncor announced its intention to divest its U.K. assets. Subsequent to 2022, the company reached an agreement for the sale of its U.K. E&P portfolio, which is expected to close in mid-2023. In the third quarter of 2022, Suncor completed the sale of its assets in Norway, which included

its 30% working interest in Oda and 17.5% working interest in the Fenja project. In addition, Suncor owns, pursuant to EPSAs, working interests in the exploration and development of oilfields in the Sirte Basin in Libya. The Libya assets continued to produce at reduced rates during 2022. 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 activities not directly attributable to any other operating segment. This segment previously included renewable energy assets, which were sold in the first quarter of 2023.

- **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., the Varennes Carbon Recycling facility, the Pathways Alliance, and the early-stage design and engineering for the proposed ATCO/Suncor hydrogen project.
- 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.

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 the COVID-19 pandemic 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 did not renew its normal course issuer bid (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 commercial and industrial non-recyclable waste into biofuels and renewable chemicals. These strategic investments, together with the company's 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. Subsequently, operations temporarily returned to a staffed fleet at Fort Hills.
- **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.
- **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.
- **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. 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 repurchase 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 clean energy.** 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. In the fourth quarter of 2021, Suncor increased its equity interest in the Varennes Carbon Recycling facility.
- **Debt reduction.** During the first quarter of 2021, consistent with its debt management and reduction strategy, Suncor cancelled $2.8 billion in bilateral 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, the company outlined its 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 ambitious near-term goals to reduce emissions across its value chain.
- **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., announced the Oil Sands Pathways to Net Zero alliance, which was expanded to include ConocoPhillips Canada Resources Corp. in November 2021. The alliance's goal was to work collectively with the federal and provincial governments to achieve net-zero GHG emissions from oil sands operations by 2050. The alliance explored 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 multisector "tie-in" projects and the implementation of other next-generation technologies.

- **Suncor assumes operatorship of Syncrude.** Pursuant to an agreement between the Syncrude joint venture owners, 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.
- **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.
- **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%.
- **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.
- **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.
- **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 NCIB 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.
- **Fort Hills resumed operation of the second primary extraction train.** Fort Hills resumed two-train operations late in the fourth quarter of 2021.

2022

- **Share repurchases.** In 2022, the company repurchased 116.9 million of its common shares at an average share price of $43.92 per common share, or the equivalent of 8.1% of its issued and outstanding common shares as at December 31, 2021.
- **Dividend increases.** In the second and fourth quarters of 2022, the Board approved increases to the quarterly dividend, raising it to $0.47 per share and $0.52 per share, respectively, both of which were the highest quarterly dividends per share in the company's history.
- **Renewal of share repurchase program.** In the first quarter of 2022, 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. During the second quarter of 2022, the NCIB was amended to allow the repurchase of up to 10% of Suncor's public float. Subsequent to 2022, the Board approved a renewal of the company's NCIB for the repurchase of up to 10% of Suncor's public float as at February 3, 2023, 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.
- **Executed debt tender offer.** In the fourth quarter of 2022, the company completed a debt tender offer and as a result, repaid approximately $3.6 billion of its various series of outstanding notes below par.
- **Restart of West White Rose Project.** In the second quarter of 2022, Suncor and the joint venture owners announced the decision to restart the West White Rose Project offshore the east coast of Canada, which is expected to extend the production life of the White Rose field. As a result of the restart decision, Suncor has increased its ownership in the White Rose assets by an additional 12.5% to approximately 39%. Production from the West White Rose Project is expected to commence in the first half of 2026.
- **Kris Smith appointed interim President and Chief Executive Officer.** Mr. Smith was named interim President and Chief Executive Officer, replacing Mark Little, as at July 8, 2022.
- **Suncor enters into agreement with Elliott Investment Management.** In the third quarter of 2022, Suncor entered into an agreement with affiliates of Elliott Investment Management (Elliott), pursuant to which Suncor appointed three new independent directors to its Board. Subsequent to 2022, the agreement was amended to extend the right for Elliott to appoint an additional director to the board from January 31, 2023, to March 17, 2023.

- **Completed sale of Norway operations.** In the third quarter of 2022, the company completed the sale of its E&P assets in Norway for gross proceeds of approximately $430 million, before closing adjustments and other closing costs.
- **Sale of the wind and solar assets.** Subsequent to 2022, Suncor completed the sale of its wind and solar assets for gross proceeds of approximately $730 million, before closing adjustments and other closing costs, to focus on hydrogen and renewable fuels to accelerate progress towards its objective to be a net-zero GHG emissions company by 2050. The sale included the company's interest in Magrath, Chin Chute, Adelaide and Forty Mile wind farms, as well as development stage renewable power assets.
- **Sale of U.K. assets.** In 2022, Suncor announced its intention to divest its U.K. E&P portfolio which include Buzzard and the Rosebank future development project. Subsequent to 2022, the company reached an agreement for the sale of its U.K. E&P portfolio for gross proceeds of approximately $1.2 billion, including a contingent consideration of approximately $338 million, before closing adjustments and other closing costs. The sale is pending regulatory approval and is expected to close in mid-2023.
- **Acquired additional interest in Fort Hills.** During the fourth quarter of 2022, the company entered into an agreement to acquire Teck's 21.3% interest in the Fort Hills Project (Fort Hills) and its associated sales and logistics agreements for $1.0 billion, subject to working capital and other closing adjustments. Subsequent to the fourth quarter of 2022, TotalEnergies EP Canada Ltd. provided notice of the exercise of its contractual right of first refusal to acquire from Teck a 6.65% interest in Fort Hills, which reduced the amount of working interest available for Suncor to purchase. As a result, on February 2, 2023, Suncor completed the acquisition of an additional 14.65% working interest in Fort Hills for $688 million, before working capital and other closing adjustments, bringing the company's and its affiliate's total aggregate working interest in Fort Hills to 68.76%.
- **Fort Hills mine improvement plan.** In the fourth quarter of 2022, the company commenced its three-year mine improvement plan, which includes an accelerated sequence of mine development relative to historical plans, during which time the asset is expected to operate at lower than 90% production rates.
- **Results of retail review.** In the fourth quarter of 2022, as a result of a comprehensive strategic review of its downstream retail business, the company announced that it would retain and continue to improve and optimize the Petro-Canada™ retail business.
- **Pathways Alliance awarded exploratory rights.** Subsequent to 2022, the Pathways Alliance was awarded exploratory rights from the Government of Alberta for the proposed carbon capture and storage hub to safely and permanently store CO_2 captured from over 20 oil sands facilities in northern Alberta.
- **Rich Kruger appointed new President and Chief Executive Officer.** Subsequent to 2022, Mr. Kruger was named Suncor's next President and Chief Executive Officer, effective April 3, 2023. Kris Smith will assume the role of Chief Financial Officer and Executive VP of Corporate Development at the conclusion of the company's annual general meeting on May 9, 2023. Alister Cowan, current Chief Financial Officer, plans to retire but will remain with the company to the end of 2023 to support transition to Mr. Smith and provide advisory services.

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 section of this AIF and the Risk Factors section of the company's annual 2022 MD&A, which section is incorporated by reference herein and available on Suncor's SEDAR profile at sedar.com.

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 that 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 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

<u>Millennium and North Steepbank</u>

Suncor pioneered the commercial development of the Athabasca oil sands beginning in 1962, achieving first production in 1967. Bitumen is currently mined from the Millennium area, which began production in 2001, and the North Steepbank area, which began production in 2011. During 2022, the company mined approximately 147.1 million tonnes of bitumen ore (2021 – 150.8 million tonnes) and processed an average of 256.9 mbbls/d of mined bitumen in its extraction facilities (2021 – 276.2 mbbls/d).

<u>Upgrading Facilities</u>

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 has progressed 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 steam generation required for Suncor's extraction and upgrading activities 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 is expected to 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 in late 2024.

During 2022, Suncor's Oil Sands Base assets averaged 314.6 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 (2021 – 313.7 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.

<u>Other Mining Leases</u>

Suncor 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

<u>Firebag</u>

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.

As at December 31, 2022, Firebag had 21 well pads in operation, with 284 SAGD well pairs and 55 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 112 MW and, in 2022, Firebag exported approximately 245 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 2022, Firebag production averaged 198.9 mbbls/d of bitumen (2021 – 206.4 mbbls/d) with a steam-to-oil ratio of 2.7 (2021 – 2.6).

<u>MacKay River</u>

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, 2022, MacKay River included nine well pads with 132 well pairs either producing or on initial steam injection. A third-party owns the on-site cogeneration unit, which Suncor operates that generates steam and electricity. There are also four OTSGs at the site for additional steam generation.

During 2022, MacKay River production averaged 32.4 mbbls/d of bitumen (2021 – 35.9 mbbls/d) with a steam-to-oil ratio of 2.8 (2021 – 2.8).

Other In Situ Leases

Suncor holds a large portfolio of In Situ lands in proximity to Fort McMurray. Two properties, Lewis and Meadow Creek, have received regulatory approval for future production. 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. The portfolio is well positioned to leverage Suncor's existing asset base and is currently being evaluated as part of Suncor's integrated Bitumen Supply Strategy.

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.

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. During 2022, Suncor's share of Fort Hills production averaged 85.1 mbbls/d of bitumen (2021 – 50.7 mbbls/d) from approximately 53.5 million tonnes of bitumen ore mined (2021 – 32.6 million tonnes).

Suncor is the operator of the Fort Hills asset. In the fourth quarter of 2022, the company commenced its three-year mine improvement plan, which includes an accelerated sequence of mine development relative to historical plans, during which time the asset is expected to operate at lower than 90% production rates. Short-term production and operating cost impacts are expected in 2023 as the company develops the Centre and North pits while building adequate ore inventory. On February 2, 2023, Suncor completed the acquisition of an additional 14.65% working interest in Fort Hills from Teck for $688 million, before working capital and other closing adjustments, bringing the company's and its affiliate's total aggregate working interest in Fort Hills to 68.76%.

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. 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 2015, the joint venture owners agreed to progress with the Mildred Lake West Extension (MLX-W) program which 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. First oil is expected in late 2025. The Mildred Lake East Extension (MLX-E) program will follow the MLX-W development if economic conditions remain suitable.

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 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, coker naphtha 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 current 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 2022, Suncor's share of Syncrude production, including internal consumption and transfers through the interconnecting pipelines, averaged 184.8 mbbls/d of SCO, intermediate products and bitumen (2021 – 172.4 mbbls/d).

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. Subsequently, in 2021, Fort Hills temporarily returned to a staffed fleet to better manage congestion and interactions between staffed and autonomous operations.Full implementation at the Oil Sands Base Millennium mine is expected to be completed over the next four years.

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. With the implementation of PASS technology, Suncor has reduced tailings volumes by more than 5% since 2020. 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 accelerates bitumen production and lowers the steam-to-oil ratio (i.e., GHG emissions intensity). This technology was successfully piloted in a half-pad configuration at Firebag in 2019-2021 and a follow-up full-pad commercial demonstration began at Firebag in the fourth quarter of 2022, focused on demonstrating a material improvement in both environmental and economic performance. Pending a successful demonstration, the technology is expected to be ready for commercial deployment in Suncor's In Situ projects as early as 2027.
- Solvent-dominated recovery process – A solvent technology wherein a hydrocarbon solvent is mixed with low-pressure steam (>80% solvent) and injected into the reservoir. The combined solvent and thermal effect are expected to materially lower the energy requirements and result in a potential step-change in both economic and environmental performance, including a greater than 50% reduction in emissions intensity relative to SAGD.
- 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 extraction processes, while reducing costs and GHG emissions.

Sales of Principal Products

Primary markets for SCO and bitumen production from Suncor's Oil Sands segment 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. In the normal course of business, Suncor enters into long-term sales agreements, which contain varying terms with respect to pricing, volume, expiry and termination. In Situ bitumen production processed by Oil Sands Base upgrading facilities in 2022 increased to 130.2 mbbls/d or 56% (2021 – 116.8 mbbls/d or 48%) 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.

	2022		2021	
Sales Volumes and Operating Revenues – Principal Products	**mbbls/d**	**% Operating Revenues**	mbbls/d	% Operating Revenues
SCO and diesel (including Syncrude)	**482.6**	**77**	465.7	70
Bitumen	**180.7**	**21**	183.8	27
Byproducts and other operating revenues(1)	**n/a**	**2**	n/a	3
	663.3		649.5	

(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 on 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. 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 2022, Suncor incurred royalties at an average rate of 12% of gross revenue for Oil Sands Operations projects, which include Base Mine, MacKay River and Firebag, (2021 – 4%), and at an average rate of 18% of gross revenue for Syncrude operations (2021 – 13%) due to higher prices. Oil Sands Operations projects and the Syncrude project are in the post-payout phase, with assessment for the year for Oil Sands Base at GRR due to a carry-forward costs balance, and MacKay River, Firebag and Syncrude at NRR.

Fort Hills is in the pre-payout phase. In 2022, Fort Hills incurred royalties at an average rate of 5% of gross revenue (2021 – 2%) due to higher prices.

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 an 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 ALE Project until an economically viable path forward with a safe and reliable return to operations could be determined. 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. Under this agreement, the company's working interest increased to 48% from approximately 38% in exchange for a cash payment from the exiting owners. This agreement also included royalty and financial support from the Government of Newfoundland and Labrador.

The ALE Project was substantially progressed in 2022, and the asset has returned to Canada, with a safe return to production expected in the second quarter of 2023. The Terra Nova ALE Project is expected to extend the production life of the Terra Nova field by approximately 10 years, providing many benefits to the Newfoundland and Labrador and Canadian economies in the form of taxes, royalties and employment.

In 2022, Terra Nova production remained offline; therefore, Suncor's share of Terra Nova production averaged nil mbbls/d of crude oil (2021 – nil mbbls/d).

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 due to natural reservoir declines. Hibernia commenced production in November 1997. As at December 31, 2022, 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 2022, 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 2022, Suncor's share of Hibernia production averaged 15.1 mbbls/d of crude oil (2021 – 19.8 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 (55 mbbls/d, net to Suncor) of crude oil and oil storage capacity of 940 mbbls. Actual production levels are lower than production capacity, due to natural declines and gas and water injection. Production from White Rose began in November 2005. As at December 31, 2022, there were 45 wells: 23 oil production wells, 16 water injection wells, three gas storage wells and three gas injection wells.

The White Rose Extensions include the North Amethyst, South White Rose Extension, and West White Rose satellite fields. First oil was achieved at North Amethyst in May 2010. Development of the South White Rose Extension began in 2013, with first oil 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 in 2017. Major development activity began in 2018. In 2020, the operator moved the project into safekeeping mode, due to COVID-19-related market uncertainty. During the second quarter of 2022, concurrent with the decision to restart the West White Rose Project by the joint venture owners, Suncor increased its ownership in the White Rose asset by 12.5% to approximately 39%. The project is expected to extend the life of the existing White Rose assets. Production is expected to commence in the first half of 2026.

In 2022, Suncor's share of White Rose production averaged 6.1 mbbls/d of crude oil (2021 – 5.4 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. Hebron has a gross oil storage capacity of 1,200 mbbls and 52 well slots. First oil was achieved in November 2017.

As at December 31, 2022, there were 30 wells: 20 oil production wells, five water injection wells, one gas injection well, one cuttings reinjection well and three water alternating gas injection wells. In 2022, Suncor's share of production averaged 29.0 mbbls/d of crude oil (2021 – 29.2 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 49 significant discovery licences and three exploration licences offshore in this area.

E&P International – Assets and Operations

Offshore U.K.

In the third quarter of 2022, the company commenced a sales process for its U.K. portfolio, including its interests in Buzzard and Rosebank located in the U.K. sector of the North Sea. Subsequent to 2022, the company reached an agreement for the sale of its U.K. E&P portfolio for gross proceeds of approximately $1.2 billion, including a contingent consideration of approximately $338 million, before closing adjustments and other closing costs. The sale is pending regulatory approval, and is expected to close in mid-2023.

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, 2022, there were 51 wells: 34 oil and gas production wells and 17 water injection wells. Buzzard Phase 2 was sanctioned in 2018 and first oil was achieved in November 2021. In 2022, Suncor's share of Buzzard production averaged 20.9 mboe/d of crude oil and natural gas (2021 – 18.7 mboe/d).

Rosebank

The Rosebank development project, in which Suncor has a 40% working interest, was discovered in December 2004 and is operated by Equinor UK 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.

Other Assets

The company holds interests in 1 U.K. exploration licence offering future offshore opportunity.

Norway (Oda, Fenja)

On September 30, 2022, the company completed the sale of its 30% working interest in Oda and its 17.5% working interest in the Fenja Development Joint Operations. In 2022, Suncor's share of Oda production averaged 3.6 mboe/d of crude oil and natural gas (2021 – 2.7 mboe/d).

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 ongoing political unrest, and the remaining value of Suncor's assets in Libya was impaired in 2015. 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, 2022, 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 3.3 mbbls/d in 2022 of crude oil (2021 – 3.4 mbbls/d).

Syria

In December 2011, due to 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. is marketed by Suncor's Energy Trading business. 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:

	2022		2021	
Sales Volumes	**mboe/d**	**% Operating Revenues**	mboe/d	% Operating Revenues
E&P Canada				
Crude oil	**51.4**	**64**	53.1	64
E&P International				
Crude oil and NGLs(1)(2)	**28.5**	**35**	29.2	35
Natural gas	**0.7**	**1**	0.5	1
Total Exploration and Production				
Crude oil and NGLs(2)	**79.9**	**99**	82.3	99
Natural gas	**0.7**	**1**	0.5	1

(1) E&P International crude oil and NGLs include 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.

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 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 one royalty is equal to 30% of net revenue. The tier two incremental royalty is on a stepped scale ranging from 10% to 22.5% to reflect oil prices from US$65/bbl Brent to above US$80/bbl Brent. During 2022, Terra Nova did not pay royalties due to suspension of production (2021 – 0%).

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 38% of gross revenue for 2022 (2021 – 35%), due to higher commodity prices.

White Rose and the Newfoundland government finalized the White Rose Fiscal Agreement in 2022, 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 7.5% depending on certain milestones. White Rose existing tier one royalty is the greater of 7.5% of gross revenue or 20% of net revenue and the tier two royalty is an additional 10% of net revenue.

The White Rose Extension (WRE) tier one royalty is equal to 10% of net revenue when Brent oil price is less than or equal to US$65/bbl, 15% when between US$65/bbl to US$80/bbl, and 30% when Brent is above US$80/bbl until tier two payout, after which the tier one royalty is 20% of net revenue. The tier two royalty is an additional 10%. The WRE also has an additional royalty equal to 1.25% to 12.50% net revenue to reflect oil prices from US$65/bbl Brent to above US$90/bbl Brent. During 2022, under the new agreement, total White Rose (including WRE) royalties averaged less than 1% of gross revenue (2021 – 6%).

The Hebron royalty structure 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 2022, Hebron reached simple basic payout increasing to 5% of gross revenue. Hebron royalties averaged 2% of gross revenue in 2022 (2021 – 1%).

E&P International

There are no royalties on oil and gas production from Offshore U.K. 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 segment, 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 yield from the Montreal refinery includes gasoline, distillate, heavy fuel oil, solvents, asphalt and petrochemicals, which are distributed primarily across Quebec and Ontario. The Montreal refinery also produces feedstock sold under a long-term supply contract with HollyFrontier's lubricants facility. 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 segment 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 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 342,500 metric tonnes in 2022 (2021 – 358,000 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 2022, the plant produced 358 million litres of ethanol (2021 – 343 million litres).

Western North America

Edmonton Refinery

The Edmonton refinery has a crude oil capacity of 146 mbbls/d and has the capability to run a full slate of feedstock sourced from Suncor's Oil Sands segment. Crude oil is supplied to the refinery via company-owned and third-party pipelines.

Feedstock is supplied from Suncor's Oil Sands segment 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, 44 mbbls/d of sour SCO and 58 mbbls/d of sweet SCO.

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 the 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 has total export capacity of 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, 2022 and 2021.

Average Daily Crude Throughput (mbbls/d, except as noted)	Montreal		Sarnia		Edmonton		Commerce City	
	2022	2021	**2022**	2021	**2022**	2021	**2022**	2021
Sweet synthetic	**20.2**	15.0	**25.0**	23.4	**53.8**	59.0	**—**	—
Sour synthetic	**—**	—	**32.4**	33.7	**45.2**	44.0	**8.4**	7.5
Diluted bitumen	**26.1**	25.4	**—**	—	**39.0**	34.2	**9.5**	7.9
Sweet conventional	**74.2**	78.0	**—**	1.4	**—**	—	**60.3**	51.5
Sour conventional	**7.8**	4.7	**20.5**	21.2	**—**	—	**10.8**	8.6
Total	**128.3**	123.1	**77.9**	79.7	**138.0**	137.2	**89.0**	75.5
Utilization (%)	**94**	90	**92**	94	**95**	94	**91**	77
Equity crude processed(1)	**19.2**	13.1	**46.7**	51.5	**99.4**	102.3	**8.4**	7.5

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

Refined Petroleum Production Yield Mix (%)	Montreal		Sarnia		Edmonton		Commerce City	
	2022	2021	**2022**	2021	**2022**	2021	**2022**	2021
Gasoline	**35**	37	**45**	45	**38**	43	**48**	50
Distillates	**39**	37	**40**	40	**56**	52	**34**	33
Other	**26**	26	**15**	15	**6**	5	**18**	17

Distribution Terminals and Pipelines

Suncor owns and operates 13 major refined product terminals across Canada (including terminals adjacent to refineries) and three product terminals in Colorado. Combined with access to facilities under long-term contractual arrangements with other parties, Suncor's North American assets are sufficient to meet the Refining and Marketing segment's current storage and distribution needs.

As at December 31, 2022, 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, 2022, this network consisted of 1,590 outlets across Canada, of which 781 locations are company-owned locations and 809 are branded dealers. Selected locations along the Trans-Canada Highway are part of 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 2022 (2021 – 4.2 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 108 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 shown in the table below.

Locations	As at December 31 **2022**	2021
Retail Service Stations – Canada		
Petro-Canada branded	**1,589**	1,583
Sunoco branded	**1**	1
	1,590	1,584
Retail Service Stations – U.S.		
Shell-branded retail service stations – Colorado/Wyoming	**143**	145
Exxon-branded retail service stations – Colorado	**46**	57
Mobil-branded retail service stations – Colorado	**31**	18
	220	220
Wholesale Cardlock Sites – Canada		
Petro-Canada-branded cardlock sites (PETRO-PASS)	**323**	323

(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

	2022		2021	
Sales Volumes	**mbbls/d**	**% Operating Revenues**	mbbls/d	% Operating Revenues
Gasoline (includes motor and aviation gasoline)				
Eastern North America	**107.0**		110.2	
Western North America	**120.6**		115.6	
	227.6	**40**	225.8	44
Distillates (includes diesel and heating oils, and aviation jet fuels)				
Eastern North America	**96.9**		94.7	
Western North America	**147.7**		133.8	
	244.6	**51**	228.5	43
Other (includes heavy fuel oil, asphalts, petrochemicals, other)				
Eastern North America	**55.4**		51.3	
Western North America	**26.0**		22.8	
	81.4	**9**	74.1	13
	553.6		528.4	

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 oil 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

Subsequent to 2022, Suncor completed the sale of its wind and solar assets which included the company's interest in Magrath, Chin Chute, Adelaide and Forty Mile wind farms, as well as development stage renewable power assets.

Following the end of the Power Purchase Agreement, in the third quarter of 2022, Suncor, with its joint venture partner, commenced the decommissioning of the 11 MW Sunbridge power asset in Saskatchewan. The asset is expected to be fully decommissioned in 2023.

Suncor's wind power projects as at December 31, 2022

Wind Power Projects		Ownership Interest (%)	Gross (MW)	Turbines	Completed
Operated by Suncor					
Forty Mile	Maleb, Alberta	100.0	200	45	2022
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

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	2022	2021
Oil Sands(1)	**10,076**	10,423
Exploration and Production	**293**	296
Refining and Marketing	**2,615**	2,673
Corporate and Shared Services(2)	**3,574**	3,530
Total	**16,558**	16,922

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

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

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

Approximately 25% of the company's employees are covered by collective agreements. The company negotiated collective agreements for Commerce City Refinery, Ottawa Terminal and Portland-Montreal Pipeline in 2022. Negotiations for 11 collective agreements covering 88% of unionized employees will take place in 2023.

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 that 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 that 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 Suncor strives for relationships that are based on transparency, mutual respect and trust.

Suncor has an Environment, Health and Safety (EH&S) policy that 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.

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.

Date of Statement

The Statement of Reserves Data and Other Oil and Gas Information outlined below is dated March 6, 2023, with an effective date of December 31, 2022. 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 Statement of Reserves Data and Other Oil and Gas Information outlined below is February 2, 2023.

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. (GLJ), contained in its report dated February 17, 2023 (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 the 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 the Industry Conditions section of this AIF and the Risk Factors section of the company's annual 2022 MD&A, which section is incorporated by reference herein and available on Suncor's SEDAR profile at sedar.com. 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.

- 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 Regulations – Climate Change and GHG Emissions 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.

- 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, 2022. 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.

- 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, tax or royalty changes, could create long-term market uncertainty, which could have a material adverse effect on Suncor's reserves.

For additional information on significant risk factors and uncertainties affecting Suncor's reserves, refer to the Risk Factors section of the company's annual 2022 MD&A, which section is incorporated by reference herein and available on Suncor's SEDAR profile at sedar.com.

Oil and Gas Reserves Tables and Notes

Summary of Oil and Gas Reserves[1]

as at December 31, 2022
(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	1,373	1,218	799	720	—	—	—	—	2,173	1,938
In Situ	262	217	79	62	—	—	—	—	341	279
E&P Canada	—	—	—	—	94	80	—	—	94	80
Total Canada	1,635	1,436	878	782	94	80	—	—	2,608	2,297
North Sea	—	—	—	—	32	32	2	2	32	32
Total Proved Developed Producing	**1,635**	**1,436**	**878**	**782**	**126**	**112**	**2**	**2**	**2,640**	**2,330**
Proved Developed Non-Producing										
Mining	—	—	—	—	—	—	—	—	—	—
In Situ	—	—	—	—	—	—	—	—	—	—
E&P Canada	—	—	—	—	—	—	—	—	—	—
Total Canada	—	—	—	—	—	—	—	—	—	—
North Sea	—	—	—	—	—	—	—	—	—	—
Total Proved Developed Non-Producing	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Proved Undeveloped										
Mining	273	248	26	23	—	—	—	—	299	271
In Situ	668	539	514	412	—	—	—	—	1,182	951
E&P Canada	—	—	—	—	59	51	—	—	59	51
Total Canada	941	787	540	435	59	51	—	—	1,540	1,273
North Sea	—	—	—	—	1	1	—	—	1	1
Total Proved Undeveloped	**941**	**787**	**540**	**435**	**60**	**51**	**—**	**—**	**1,541**	**1,274**
Proved										
Mining	1,646	1,467	826	743	—	—	—	—	2,472	2,210
In Situ	930	756	593	474	—	—	—	—	1,523	1,230
E&P Canada	—	—	—	—	153	131	—	—	153	131
Total Canada	2,576	2,223	1,419	1,217	153	131	—	—	4,148	3,571
North Sea	—	—	—	—	33	33	2	2	33	33
Total Proved	**2,576**	**2,223**	**1,419**	**1,217**	**185**	**163**	**2**	**2**	**4,181**	**3,604**
Probable										
Mining	302	265	383	316	—	—	—	—	685	582
In Situ	1,331	1,020	244	182	—	—	—	—	1,575	1,202
E&P Canada	—	—	—	—	114	85	—	—	114	85
Total Canada	1,633	1,285	626	498	114	85	—	—	2,374	1,868
North Sea	—	—	—	—	11	11	1	1	11	11
Total Probable	**1,633**	**1,285**	**626**	**498**	**125**	**96**	**1**	**1**	**2,385**	**1,879**
Proved Plus Probable										
Mining	1,948	1,732	1,209	1,059	—	—	—	—	3,157	2,791
In Situ	2,261	1,776	836	656	—	—	—	—	3,098	2,432
E&P Canada	—	—	—	—	267	215	—	—	267	215
Total Canada	4,210	3,508	2,045	1,715	267	215	—	—	6,521	5,439
North Sea	—	—	—	—	43	43	3	3	44	44
Total Proved Plus Probable	**4,210**	**3,508**	**2,045**	**1,715**	**310**	**259**	**3**	**3**	**6,565**	**5,483**

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, 2022
(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, 2021	1,737	403	2,140	787	461	1,248	—	—	—	—	—	—	2,524	864	3,387
Extensions & Improved Recovery[7]	—	110	110	—	3	3	—	—	—	—	—	—	—	113	113
Technical Revisions[8]	44	(210)	(165)	73	(82)	(9)	—	—	—	—	—	—	117	(291)	(174)
Discoveries[9]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Acquisitions[10]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions[11]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors[12]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Production[13]	(136)	—	(136)	(34)	—	(34)	—	—	—	—	—	—	(169)	—	(169)
December 31, 2022	**1,646**	**302**	**1,948**	**826**	**383**	**1,209**	**—**	**—**	**—**	**—**	**—**	**—**	**2,472**	**685**	**3,157**
In Situ															
December 31, 2021	990	1,275	2,265	571	336	907	—	—	—	—	—	—	1,561	1,611	3,172
Extensions & Improved Recovery[7]	6	(6)	—	2	(2)	—	—	—	—	—	—	—	8	(8)	—
Technical Revisions[8]	(26)	62	36	52	(90)	(39)	—	—	—	—	—	—	26	(28)	(3)
Discoveries[9]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Acquisitions[10]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions[11]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors[12]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Production[13]	(40)	—	(40)	(32)	—	(32)	—	—	—	—	—	—	(72)	—	(72)
December 31, 2022	**930**	**1,331**	**2,261**	**593**	**244**	**836**	**—**	**—**	**—**	**—**	**—**	**—**	**1,523**	**1,575**	**3,098**
E&P Canada															
December 31, 2021	—	—	—	—	—	—	113	103	215	—	—	—	113	103	215
Extensions & Improved Recovery[7]	—	—	—	—	—	—	48	14	61	—	—	—	48	14	61
Technical Revisions[8]	—	—	—	—	—	—	6	(4)	1	—	—	—	6	(4)	1
Discoveries[9]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Acquisitions[10]	—	—	—	—	—	—	2	1	3	—	—	—	2	1	3
Dispositions[11]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors[12]	—	—	—	—	—	—	3	1	4	—	—	—	3	1	4
Production[13]	—	—	—	—	—	—	(19)	—	(19)	—	—	—	(19)	—	(19)
December 31, 2022	**—**	**—**	**—**	**—**	**—**	**—**	**153**	**114**	**267**	**—**	**—**	**—**	**153**	**114**	**267**
Total Canada															
December 31, 2021	2,727	1,678	4,405	1,358	797	2,155	113	103	215	—	—	—	4,197	2,578	6,775
Extensions & Improved Recovery[7]	6	104	110	2	1	3	48	14	61	—	—	—	56	118	174
Technical Revisions[8]	19	(148)	(129)	124	(172)	(48)	6	(4)	1	—	—	—	149	(324)	(176)
Discoveries[9]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Acquisitions[10]	—	—	—	—	—	—	2	1	3	—	—	—	2	1	3
Dispositions[11]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors[12]	—	—	—	—	—	—	3	1	4	—	—	—	3	1	4
Production[13]	(176)	—	(176)	(65)	—	(65)	(19)	—	(19)	—	—	—	(260)	—	(260)
December 31, 2022	**2,576**	**1,633**	**4,210**	**1,419**	**626**	**2,045**	**153**	**114**	**267**	**—**	**—**	**—**	**4,148**	**2,374**	**6,521**

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, 2022
(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
North Sea															
December 31, 2021	—	—	—	—	—	—	46	16	63	13	6	19	49	17	66
Extensions & Improved Recovery[7]	—	—	—	—	—	—	5	(4)	1	1	(1)	—	5	(4)	1
Technical Revisions[8]	—	—	—	—	—	—	(4)	2	(2)	1	—	1	(4)	2	(2)
Discoveries[9]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Acquisitions[10]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions[11]	—	—	—	—	—	—	(7)	(3)	(11)	(11)	(4)	(15)	(9)	(4)	(13)
Economic Factors[12]	—	—	—	—	—	—	1	—	1	—	—	—	1	—	1
Production[13]	—	—	—	—	—	—	(9)	—	(9)	(2)	—	(2)	(9)	—	(9)
December 31, 2022	**—**	**—**	**—**	**—**	**—**	**—**	**33**	**11**	**43**	**2**	**1**	**3**	**33**	**11**	**44**
Total															
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
Extensions & Improved Recovery[7]	6	104	110	2	1	3	53	10	63	1	(1)	—	61	114	176
Technical Revisions[8]	19	(148)	(129)	124	(172)	(48)	2	(2)	(1)	1	—	1	145	(322)	(178)
Discoveries[9]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Acquisitions[10]	—	—	—	—	—	—	2	1	3	—	—	—	2	1	3
Dispositions[11]	—	—	—	—	—	—	(7)	(3)	(11)	(11)	(4)	(15)	(9)	(4)	(13)
Economic Factors[12]	—	—	—	—	—	—	5	1	5	—	—	—	5	1	5
Production[13]	(176)	—	(176)	(65)	—	(65)	(28)	—	(28)	(2)	—	(2)	(269)	—	(269)
December 31, 2022	**2,576**	**1,633**	**4,210**	**1,419**	**626**	**2,045**	**185**	**125**	**310**	**2**	**1**	**3**	**4,181**	**2,385**	**6,565**

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, 2022

(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 52 mmbbls, proved of 52 mmbbls, probable of 19 mmbbls and proved plus probable of 71 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 45 mmbbls, proved of 45 mmbbls, probable of 15 mmbbls and proved plus probable of 59 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 7 mmbbls, probable of (6) mmbbls and proved plus probable of 0.6 mmbbls.

(6) Conventional natural gas includes immaterial amounts of 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 2022 are primarily a result of additions from Syncrude MLX-E and the West White Rose Project.

(8) Technical revisions include changes in previous estimates resulting from new technical data or revised interpretations. Changes in 2022 are primarily due to new information obtained during the year, including drilling results and ongoing field performance. In 2022, Mining changes are primarily due to mine plan updates at Millennium/North Steepbank and Fort Hills, and risk revisions at Fort Hills. In 2022, 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 2022.

(10) Acquisitions are additions to reserves estimates as a result of purchasing interests in oil and gas properties. In 2022, Suncor increased its working interest in White Rose.

(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 2022, Suncor divested its interest in Norway. See the 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, 2022
(forecast prices and costs)

	(in $ millions, discounted at % per year)					Unit Value[2]
	0%	5%	10%	15%	20%	($/boe)
Proved Developed Producing						
Mining	14,547	29,170	24,822	20,356	17,039	12.81
In Situ	11,594	10,247	9,123	8,213	7,474	32.66
E&P Canada	3,188	3,182	3,077	2,946	2,813	38.59
Total Canada	29,329	42,598	37,023	31,514	27,326	16.11
North Sea	2,050	1,943	1,808	1,676	1,556	56.05
Total Proved Developed Producing	**31,380**	**44,541**	**38,831**	**33,191**	**28,882**	**16.67**
Proved Developed Non-Producing						
Mining	—	—	—	—	—	—
In Situ	—	—	—	—	—	—
E&P Canada	14	13	11	10	9	83.01
Total Canada	14	13	11	10	9	83.01
North Sea	—	—	—	—	—	
Total Proved Developed Non-Producing	**14**	**13**	**11**	**10**	**9**	**83.01**
Proved Undeveloped						
Mining	4,016	3,057	1,955	1,222	758	7.21
In Situ	32,885	18,266	11,067	7,209	4,975	11.64
E&P Canada	2,095	1,627	1,219	886	622	24.02
Total Canada	38,996	22,949	14,241	9,317	6,354	11.19
North Sea	18	15	12	9	7	18.41
Total Proved Undeveloped	**39,014**	**22,964**	**14,253**	**9,327**	**6,362**	**11.19**
Proved						
Mining	18,563	32,226	26,777	21,578	17,796	12.12
In Situ	44,479	28,512	20,191	15,422	12,449	16.41
E&P Canada	5,297	4,821	4,307	3,842	3,445	32.98
Total Canada	68,339	65,560	51,274	40,842	33,690	14.36
North Sea	2,069	1,958	1,820	1,686	1,563	55.31
Total Proved	**70,408**	**67,517**	**53,095**	**42,527**	**35,253**	**14.73**
Probable						
Mining	19,065	9,744	5,824	4,026	3,072	10.01
In Situ	72,756	20,726	8,269	4,427	2,917	6.88
E&P Canada	6,801	4,829	3,521	2,641	2,035	41.49
Total Canada	98,621	35,299	17,614	11,094	8,024	9.43
North Sea	993	789	632	515	430	56.90
Total Probable	**99,614**	**36,088**	**18,246**	**11,610**	**8,455**	**9.71**
Proved Plus Probable						
Mining	37,628	41,970	32,601	25,604	20,869	11.68
In Situ	117,235	49,238	28,460	19,849	15,366	11.70
E&P Canada	12,098	9,650	7,827	6,483	5,480	36.33
Total Canada	166,960	100,859	68,888	51,936	41,714	12.67
North Sea	3,062	2,747	2,452	2,201	1,993	55.71
Total Proved Plus Probable	**170,022**	**103,606**	**71,340**	**54,137**	**43,707**	**13.01**

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, 2022
(forecast prices and costs)

	(in $ millions, discounted at % per year)				
	0%	5%	10%	15%	20%
Proved Developed Producing					
Mining	5,924	22,526	19,514	15,977	13,329
In Situ	9,043	7,976	7,079	6,351	5,764
E&P Canada	2,581	2,594	2,509	2,398	2,286
Total Canada	17,548	33,096	29,101	24,727	21,378
North Sea	356	381	373	354	332
Total Proved Developed Producing	**17,904**	**33,477**	**29,475**	**25,081**	**21,710**
Proved Developed Non-Producing					
Mining	—	—	—	—	—
In Situ	—	—	—	—	—
E&P Canada	11	9	8	8	7
Total Canada	11	9	8	8	7
North Sea	—	—	—	—	—
Total Proved Developed Non-Producing	**11**	**9**	**8**	**8**	**7**
Proved Undeveloped					
Mining	2,669	2,163	1,345	795	451
In Situ	25,065	13,701	8,184	5,265	3,591
E&P Canada	1,406	1,093	802	558	363
Total Canada	29,140	16,957	10,331	6,618	4,404
North Sea	11	10	10	9	8
Total Proved Undeveloped	**29,151**	**16,967**	**10,341**	**6,627**	**4,412**
Proved					
Mining	8,593	24,689	20,859	16,772	13,779
In Situ	34,108	21,677	15,263	11,616	9,354
E&P Canada	3,998	3,696	3,320	2,964	2,656
Total Canada	46,698	50,062	39,441	31,352	25,789
North Sea	367	391	383	363	340
Total Proved	**47,066**	**50,453**	**39,824**	**31,715**	**26,130**
Probable					
Mining	15,395	7,633	4,414	2,983	2,246
In Situ	55,868	15,765	6,304	3,406	2,265
E&P Canada	5,341	3,751	2,703	2,006	1,531
Total Canada	76,604	27,149	13,421	8,396	6,042
North Sea	435	339	264	209	170
Total Probable	**77,040**	**27,488**	**13,685**	**8,605**	**6,212**
Proved Plus Probable					
Mining	23,988	32,322	25,272	19,755	16,025
In Situ	89,975	37,442	21,567	15,022	11,619
E&P Canada	9,339	7,447	6,023	4,971	4,187
Total Canada	123,302	77,211	52,862	39,748	31,831
North Sea	803	730	647	572	511
Total Proved Plus Probable	**124,105**	**77,941**	**53,509**	**40,320**	**32,342**

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

Total Future Net Revenues[1]

as at December 31, 2022
(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	214,902	23,300	105,510	27,347	44,198	14,547	8,623	5,924
In Situ	34,662	5,497	13,186	3,571	813	11,594	2,551	9,043
E&P Canada	10,395	1,549	2,754	308	2,596	3,188	607	2,581
Total Canada	259,958	30,346	121,449	31,226	47,607	29,329	11,782	17,548
North Sea	3,628	—	1,116	17	445	2,050	1,694	356
Total Proved Developed Producing	**263,587**	**30,346**	**122,565**	**31,244**	**48,052**	**31,380**	**13,476**	**17,904**
Proved Developed Non-Producing								
Mining	—	—	—	—	—	—	—	—
In Situ	—	—	—	—	—	—	—	—
E&P Canada	20	6	—	—	—	14	4	11
Total Canada	20	6	—	—	—	14	4	11
North Sea	—	—	—	—	—	—	—	—
Total Proved Developed Non-Producing	**20**	**6**	**—**	**—**	**—**	**14**	**4**	**11**
Proved Undeveloped								
Mining	32,801	3,049	19,343	4,450	1,942	4,016	1,347	2,669
In Situ	122,983	22,853	46,706	19,268	1,272	32,885	7,820	25,065
E&P Canada	6,611	984	1,390	1,966	177	2,095	689	1,406
Total Canada	162,396	26,887	67,439	25,684	3,391	38,996	9,856	29,140
North Sea	72	—	11	43	—	18	7	11
Total Proved Undeveloped	**162,468**	**26,887**	**67,449**	**25,727**	**3,391**	**39,014**	**9,863**	**29,151**
Proved								
Mining	247,703	26,349	124,853	31,797	46,140	18,563	9,970	8,593
In Situ	157,645	28,351	59,892	22,839	2,085	44,479	10,372	34,108
E&P Canada	17,026	2,539	4,144	2,274	2,773	5,297	1,299	3,998
Total Canada	422,374	57,238	188,889	56,910	50,997	68,339	21,641	46,698
North Sea	3,700	—	1,126	60	445	2,069	1,702	367
Total Proved	**426,074**	**57,238**	**190,015**	**56,971**	**51,442**	**70,408**	**23,343**	**47,066**
Probable								
Mining	80,029	12,009	35,299	8,578	5,079	19,065	3,669	15,395
In Situ	250,515	54,331	86,804	34,962	1,663	72,756	16,888	55,868
E&P Canada	13,007	3,591	1,691	702	221	6,801	1,460	5,341
Total Canada	343,550	69,931	123,794	44,242	6,963	98,621	22,017	76,604
North Sea	1,312	—	287	5	27	993	558	435
Total Probable	**344,863**	**69,931**	**124,081**	**44,247**	**6,990**	**99,614**	**22,574**	**77,040**
Proved Plus Probable								
Mining	327,732	38,358	160,152	40,375	51,219	37,628	13,639	23,988
In Situ	408,160	82,681	146,696	57,801	3,748	117,235	27,259	89,975
E&P Canada	30,033	6,130	5,835	2,976	2,994	12,098	2,759	9,339
Total Canada	765,925	127,169	312,683	101,152	57,961	166,960	43,658	123,302
North Sea	5,013	—	1,413	66	472	3,062	2,259	803
Total Proved Plus Probable	**770,937**	**127,169**	**314,096**	**101,218**	**58,433**	**170,022**	**45,917**	**124,105**

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

Future Net Revenues by Product Type[1]
as at December 31, 2022
(forecast prices and costs)

(before income taxes, discounted at 10% per year)	$ millions	Unit Value $/boe[2]
Proved Developed Producing		
SCO	25,478	17.75
Bitumen	8,467	10.83
Light Crude Oil & Medium Crude Oil	3,033	45.42
Heavy Crude Oil	1,836	40.87
Conventional Natural Gas[3]	17	56.13
Total Proved Developed Producing	**38,831**	**16.67**
Proved		
SCO	33,130	14.90
Bitumen	13,838	11.37
Light Crude Oil & Medium Crude Oil	4,413	37.24
Heavy Crude Oil	1,697	37.96
Conventional Natural Gas[3]	18	55.30
Total Proved	**53,095**	**14.73**
Proved Plus Probable		
SCO	45,554	12.98
Bitumen	15,507	9.04
Light Crude Oil & Medium Crude Oil	7,815	39.14
Heavy Crude Oil	2,436	41.10
Conventional Natural Gas[3]	29	55.75
Total Proved Plus Probable	**71,340**	**13.01**

(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 2034 and 100% thereafter.

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, 2023), Sproule Associates Limited (dated December 31, 2022) and McDaniel & Associates Consultants Ltd. (dated January 1, 2023), all of whom are independent qualified reserves evaluators. 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 2023, 2.3% in 2024 and 2.0% thereafter.

Carbon cost compliance for Canadian reserves are based on the federal Greenhouse Gas Pollution Pricing Act which escalates from $65/tonne in 2023 to $170/tonne in 2030. For the Oil Sands projects, the compliance cost determination incorporates the Alberta Government's December 2022 amendment to TIER.

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
2022[(8)]	101.20	94.25	75.95	120.10	122.05	4.85	32.15
2023	84.67	80.33	76.54	103.77	106.22	4.23	45.37
2024	82.69	78.50	77.75	97.74	101.35	4.40	35.75
2025	81.03	76.95	77.54	95.27	98.94	4.21	26.05
2026	81.39	77.61	80.07	95.58	100.19	4.27	22.38
2027	82.65	79.16	81.89	97.07	101.74	4.34	21.23
2028	84.29	80.75	84.02	99.01	103.78	4.43	21.66
2029	85.98	82.36	85.73	100.99	105.85	4.51	22.09
2030	87.70	84.01	87.44	103.01	107.97	4.60	22.53
2031	89.46	85.69	89.20	105.07	110.13	4.69	22.98
2032	91.25	87.40	91.11	106.69	112.33	4.79	23.44
2033	93.07	89.15	92.93	108.83	114.58	4.89	23.91
2034	94.93	90.93	94.79	111.00	116.87	4.98	24.39
2035	96.83	92.75	96.68	113.22	119.21	5.08	24.88
2036	98.77	94.60	98.62	115.49	121.59	5.18	25.38
2037	100.75	96.50	100.59	117.80	124.03	5.29	25.89
2038+	+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 North Sea 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 North Sea reserves.

(8) Prices for 2022 reflect the company's historical weighted average prices.

Forecast Foreign Exchange Rates Impacting Forecast Prices

Forecast	US$/Cdn$ Exchange Rate	Cdn$/€ Exchange Rate	Cdn$/£ Exchange Rate
Year			
2023	0.745	1.454	1.615
2024	0.765	1.427	1.612
2025	0.768	1.443	1.640
2026	0.772	1.445	1.652
2027	0.775	1.439	1.656
2028+	0.775	1.439	1.656

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 2022 audited Consolidated Financial Statements and the annual 2022 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, 2022
(forecast prices and costs)

($ millions)	2023	2024	2025	2026	2027	Remainder	Total	Discounted at 10%
Proved								
Mining	2,739	2,918	2,571	2,297	2,430	18,844	31,797	18,350
In Situ	804	1,224	922	588	872	18,430	22,839	8,934
E&P Canada	451	484	394	197	122	626	2,274	1,699
Total Canada	3,994	4,625	3,887	3,082	3,423	37,899	56,910	28,983
North Sea	47	3	2	2	1	5	60	54
Total Proved	**4,041**	**4,628**	**3,889**	**3,084**	**3,425**	**37,904**	**56,971**	**29,036**
Proved Plus Probable								
Mining	2,908	3,129	2,802	2,625	2,759	26,152	40,375	20,991
In Situ	829	881	772	814	722	53,784	57,801	10,205
E&P Canada	524	610	530	333	208	771	2,976	2,198
Total Canada	4,260	4,621	4,104	3,772	3,688	80,707	101,152	33,394
North Sea	50	3	2	2	1	8	66	57
Total Proved Plus Probable	**4,310**	**4,623**	**4,106**	**3,775**	**3,690**	**80,714**	**101,218**	**33,451**

(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 2023 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 the West White Rose Project, and development drilling at Hebron and Hibernia.
- For E&P International, capital investments related to the Rosebank development and development drilling at Buzzard until the assets are divested.

Future development costs 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 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 and the possible future use of the site.

As at December 31, 2022, Suncor estimated its undiscounted, uninflated abandonment and reclamation costs for its upstream assets to be approximately $22.1 billion (discounted at 10%, approximately $4.1 billion). In 2022, the company recognized an increased liability primarily due to water treatment costs for mining assets. The Refining and Marketing liabilities are estimated at $0.3 billion, undiscounted and uninflated. Abandonment and reclamation cost estimates are limited to current disturbances at December 31, 2022 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, 2022. Suncor estimates that it will incur $1.2 billion of its identified abandonment and reclamation costs during the next three years (undiscounted: 2023 – $0.4 billion, 2024 – $0.4 billion, 2025 – $0.4 billion), more than 86% 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 segment include costs related to the reclamation of disturbed land from oil sands mining activities, future mining disturbances, the treatment of oil sands tailings, water treatment, 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. Abandonment liabilities include 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 $58.4 billion (inflated and undiscounted) has been deducted as abandonment and reclamation costs in estimating the future net revenues from proved plus probable reserves, including $55.0 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)

	2020		2021		**2022**	
	First Attributed	Total as at December 31, 2020	First Attributed	Total as at December 31, 2021	**First Attributed**	**Total as at December 31, 2022**
SCO (mmbbls)						
Mining	297	297	—	295	**—**	**273**
In Situ	—	746	2	715	**6**	**668**
Total SCO	297	1,042	2	1,010	**6**	**941**
Bitumen (mmbbls)						
Mining	—	—	—	—	**—**	**26**
In Situ	—	523	1	478	**2**	**514**
Total bitumen	—	523	1	478	**2**	**540**
Light crude oil & medium crude oil (mmbbls)						
E&P Canada	4	18	—	13	**46**	**59**
North Sea	1	8	1	7	**1**	**1**
Total light crude oil & medium crude oil	6	25	1	20	**47**	**60**
Heavy crude oil (mmbbls)						
E&P Canada	—	15	—	2	**—**	**—**
North Sea	—	—	—	—	**—**	**—**
Total heavy crude oil	—	15	—	2	**—**	**—**
Conventional natural gas (bcfe)						
E&P Canada	—	—	—	—	**—**	**—**
North Sea(2)	—	11	—	11	**—**	**—**
Total conventional natural gas	—	11	—	11	**—**	**—**
Total (mmboe)	302	1,608	3	1,513	**55**	**1,541**

(1) Figures may not add due to rounding.

(2) Includes immaterial amounts of NGLs.

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

	2020		2021		**2022**	
	First Attributed	Total as at December 31, 2020	First Attributed	Total as at December 31, 2021	**First Attributed**	**Total as at December 31, 2022**
SCO (mmbbls)						
Mining	—	23	—	23	**110**	**133**
In Situ	116	1,195	—	1,185	**—**	**1,249**
Total SCO	116	1,218	—	1,208	**110**	**1,382**
Bitumen (mmbbls)						
Mining	—	—	—	—	**3**	**3**
In Situ	24	289	—	283	**—**	**175**
Total bitumen	24	289	—	283	**3**	**178**
Light crude oil & medium crude oil (mmbbls)						
E&P Canada	23	55	8	60	**15**	**76**
North Sea	—	3	—	3	**—**	**1**
Total light crude oil & medium crude oil	24	58	8	63	**15**	**77**
Heavy crude oil (mmbbls)						
E&P Canada	—	8	—	2	**—**	**—**
North Sea	—	—	—	—	**—**	**—**
Total heavy crude oil	—	8	—	2	**—**	**—**
Conventional natural gas (bcfe)						
E&P Canada	—	—	—	—	**—**	**—**
North Sea[2]	—	3	—	4	**—**	**—**
Total conventional natural gas	—	3	—	4	**—**	**—**
Total (mmboe)	163	1,573	8	1,556	**129**	**1,638**

(1) Figures may not add due to rounding.

(2) Includes immaterial amounts of NGLs.

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. Suncor plans to proceed with the 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.

In Situ

Undeveloped In Situ reserves, which constitute approximately 77% of Suncor's gross proved undeveloped reserves and 87% 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 forecasts future proved undeveloped and probable undeveloped reserves development activity. These 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 8% of Suncor's gross probable undeveloped reserves and relate to the Syncrude MLX West and East mining areas, which received regulatory approval in 2019 and 2020, respectively. Development of MLX-W consists of typical mine development activities; construction activities were restarted in 2021 and continued through 2022. MLX-W reserves will remain as undeveloped until its major components, such as a bridge, are completed. Development of MLX-E consists of typical mine development activities in addition to relocation of infrastructure that currently occupies the lease footprint and construction of a production haul road from the lease; project engineering commenced in 2022. MLX-E reserves will remain as undeveloped until its major components, such as infrastructure relocation and the production haul road, are completed. Both projects will utilize existing ore processing and extraction facilities at Syncrude's Mildred Lake operation and are expected to sustain bitumen production levels at Mildred Lake after resource depletion at the North Mine.

E&P

Undeveloped conventional reserves (light crude oil and medium crude oil, heavy crude oil and natural gas) constitute approximately 4% of Suncor's gross proved undeveloped reserves and approximately 5% of Suncor's gross probable undeveloped reserves and relate to the company's offshore E&P assets, mainly associated with future drilling at Hebron, Hibernia and White Rose. 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.

Properties with no Attributed Reserves

The following table shows a summary of properties to which no reserves are attributed as at December 31, 2022. 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	2,040,041	774,873
Libya	3,117,800	1,422,900
Syria	345,194	345,194
U.K.	32,750	13,106
Total	**5,535,785**	**2,556,073**

Suncor's properties with no attributed reserves range from 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. For additional information on risks and uncertainties, refer to the Risk Factors section of Suncor's annual 2022 MD&A, which section is incorporated by reference herein and available on the company's SEDAR profile at sedar.com.

In 2023, Suncor's rights to 115,708 net hectares in Canada are scheduled to expire. The lands expiring in 2023 include approximately 12,826 net hectares in In Situ and 23,040 net hectares in Mining. Substantial portions of expiring lands may have their tenure continued beyond 2023 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 Libya. Suncor has work commitments primarily for conducting seismic programs and drilling exploration wells. As at December 31, 2022, 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, 2022.

	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)	471.0	471.0	17.0	17.0	—	—	—	—
Newfoundland and Labrador	76.0	18.6	26.0	11.4	—	—	—	—
Offshore U.K.	26.0	7.8	8.0	2.4	—	—	—	—
Other International(5)	—	—	422.0	212.6	—	—	6.0	6.0
Total	**573.0**	**497.4**	**473.0**	**243.4**	**—**	**—**	**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. 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 multilateral 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. As 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, 2022.

($ millions)	Exploration Costs	Proved Property Acquisition Costs	Unproved Property Acquisition Costs	Development Costs	Total
Canada – Mining and In Situ	38	—	—	3,633	3,671
Canada – E&P Canada	4	—	—	448	452
Total Canada	**42**	**—**	**—**	**4,081**	**4,123**
North Sea	50	—	—	100	150
Other international	6	—	—	—	6
Total	**98**	**—**	**—**	**4,181**	**4,279**

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, 2022.

	Exploratory Wells[1]		Development Wells	
Total Number of Wells Completed	Gross	Net	Gross	Net
Canada – Oil Sands				
Oil	—	—	36.0	36.0
Service[2]	—	—	33.0	33.0
Stratigraphic test[3]	41.0	22.0	683.0	442.6
Total	**41.0**	**22.0**	**752.0**	**511.6**
Canada – E&P Canada				
Oil	—	—	2.0	0.4
Dry hole	—	—	—	—
Natural gas	—	—	—	—
Service[2]	—	—	1.0	0.2
Stratigraphic test	—	—	—	—
Total	**—**	**—**	**3.0**	**0.6**
Total Canada				
Oil	—	—	38.0	36.4
Dry hole	—	—	—	—
Natural gas	—	—	—	—
Service[2]	—	—	34.0	33.2
Stratigraphic test	41.0	22.0	683.0	442.6
Total	**41.0**	**22.0**	**755.0**	**512.2**
North Sea				
Oil	—	—	3.0	0.7
Dry hole	—	—	—	—
Service[2]	—	—	1.0	0.2
Stratigraphic test	—	—	—	—
Total	**—**	**—**	**4.0**	**0.9**

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

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

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

Significant exploration and development activities in 2022 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 continued 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, planned maintenance activities and the ongoing development of MLX-W.
- 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, development work at the West White Rose Project and drilling activities at Hebron.
- For E&P International, work on the Norwegian Fenja Project, which was subsequently sold in the third quarter of 2022.

For significant exploration and development activities expected to occur in 2023 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]

2022	Q1	Q2	Q3	Q4	Year Ended
Canada – Oil Sands					
Upgraded product (SCO and diesel) production (mbbls/d)					
Oil Sands operations	333.8	294.0	268.8	316.5	303.1
Syncrude	181.5	189.0	136.3	201.0	176.9
Total upgraded production	515.3	483.0	405.1	517.5	480.0
Non-upgraded bitumen production (mbbls/d)					
Oil Sands operations	82.9	71.1	145.1	102.0	100.4
Fort Hills	87.5	87.4	95.8	68.6	84.8
Total Oil Sands non-upgraded bitumen production	170.4	158.5	240.9	170.6	185.2
Total production (mbbls/d)	**685.7**	**641.5**	**646.0**	**688.1**	**665.2**
Netbacks[3][4]					
Non-upgraded bitumen ($/bbl)					
Average price realized[2]	96.49	113.41	79.60	54.52	84.63
Royalties	(15.17)	(19.71)	(11.41)	(10.37)	(13.81)
Operating costs	(21.37)	(22.38)	(16.37)	(22.55)	(20.27)
Netback	59.95	71.32	51.82	21.60	50.55
Upgraded – net SCO and diesel ($/bbl)					
Average price realized[2]	114.37	137.17	119.27	105.38	118.88
Royalties	(16.60)	(26.57)	(15.20)	(10.66)	(17.27)
Operating costs	(34.63)	(35.81)	(42.94)	(37.71)	(37.55)
Netback	63.14	74.79	61.13	57.01	64.06
Average Oil Sands segment ($/bbl)					
Average price realized[2]	110.27	131.28	105.16	92.33	109.57
Royalties	(16.28)	(24.87)	(13.85)	(10.59)	(16.33)
Operating costs	(31.59)	(32.48)	(33.49)	(33.82)	(32.85)
Netback	62.40	73.93	57.82	47.92	60.39
Exploration and Production – light crude oil & medium crude oil					
Exploration and Production Canada (mbbls/d)	51.2	52.9	47.5	49.1	50.2
Exploration and Production North Sea (mboe/d)	29.2	25.8	30.6	25.9	27.8
Total production volumes (mboe/d)	**80.4**	**78.7**	**78.1**	**75.0**	**78.0**
Netbacks[3][4]					
Canada – light crude oil & medium crude oil ($/bbl)					
Average price realized[2]	122.13	140.24	130.37	112.93	128.07
Royalties	(19.47)	(19.58)	(17.52)	(15.70)	(18.25)
Operating costs	(13.15)	(13.36)	(13.85)	(20.17)	(14.69)
Netback	89.51	107.30	99.00	77.06	95.13
North Sea – light crude oil & medium crude oil ($/boe)[5]					
Average price realized[2]	113.60	127.84	137.29	128.86	126.61
Operating costs	(8.79)	(10.96)	(9.95)	(9.16)	(9.66)
Netback[4]	104.81	116.88	127.34	119.70	116.95

(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 contain non-GAAP financial measures. 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, 2022.

	SCO	Bitumen	Light Crude Oil & Medium Crude Oil
	mbbls/d	mbbls/d	mboe/d
Mining – Suncor	203.7	—	—
Mining – Syncrude	176.9	—	—
Mining – Fort Hills	—	84.8	—
Firebag	99.4	68.0	—
MacKay River	—	32.4	—
Buzzard	—	—	20.9
Hibernia	—	—	15.1
White Rose	—	—	6.1
Terra Nova	—	—	—
Hebron[2]	—	—	29.0

(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 2023 that are included in the estimates of proved reserves and probable reserves as at December 31, 2022.

	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	445	405	187	159	56	51	—	—	688	615
Probable	32	28	16	12	4	3	—	—	51	43
Proved Plus Probable	476	433	203	171	60	55	—	—	739	658
North Sea[3]										
Proved	—	—	—	—	19	19	3	3	19	19
Probable	—	—	—	—	2	2	1	1	2	2
Proved Plus Probable	—	—	—	—	21	21	4	4	21	21
Total[1][2]										
Proved	445	405	187	159	75	70	3	3	707	634
Probable	32	28	16	12	6	5	1	1	53	45
Proved Plus Probable	476	433	203	171	80	75	4	4	761	679

(1) Figures may not add due to rounding.

(2) Conventional natural gas includes immaterial amounts of NGLs.

(3) Subsequent to 2022, the company reached an agreement for the sale of its U.K. E&P portfolio, which is expected to close in mid-2023.

The following properties each account for approximately 20% or more of total estimated production for 2023.

Proved

- From Millennium and North Steepbank: 184 mbbls/d of SCO, which represents approximately 26% of total estimated production for 2023.
- From Firebag: 173 mbbls/d of SCO and bitumen (103 mbbls/d and 70 mbbls/d, respectively), which represents approximately 24% of total estimated production for 2023.
- From Syncrude: 167 mbbls/d of SCO and bitumen (159 mbbls/d and 8 mbbls/d, respectively), which represents approximately 24% of total estimated production for 2023.

Proved Plus Probable

- From Millennium and North Steepbank: 196 mbbls/d of SCO, which represents approximately 26% of total estimated production for 2023.
- From Firebag: 186 mbbls/d of SCO and bitumen (107 mbbls/d and 79 mbbls/d, respectively), which represents approximately 25% of total estimated production for 2023.
- From Syncrude: 181 mbbls/d of SCO and bitumen (173 mbbls/d and 8 mbbls/d, respectively), which represents approximately 24% of total estimated production for 2023.

None of the company's light and medium crude oil production associated with its E&P Canada and Offshore U.K. assets accounts for 20% or more of the total estimated production for 2023.

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 2022 audited Consolidated Financial Statements and related annual 2022 MD&A.

Tax Horizon

In 2022, 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 2023.

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.

Under the Canada-United States-Mexico Agreement (CUSMA), free flow of oil exports between Canada, Mexico and the United States is allowed and requires the parties to treat imported goods no less favourably than domestic goods. 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 2022 was 15% for active business income, including resource income. The average provincial income tax rate for Suncor in 2022 was approximately 9.16%, resulting in a total Canadian income tax rate of approximately 24.16%.

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 approximately 50% for 2022, made up of the corporate income tax rate, the supplemental charge, and the Energy (Oil and Gas) Profits Levy. The levy applicable to 2022 oil and gas profits in the U.K. is 25% and was enacted on May 26, 2022. In the fourth quarter of 2022, the levy was increased by an additional 10% effective January 1, 2023. Prior to the sale of the Norway assets, operations in the country were subject to a tax rate of 78%.

Amounts presented in Suncor's 2022 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 construct and 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, transitional energy activities, 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 energy 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 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.

The rate and pace of change of consumer behaviour, such as the adoption of zero-emission vehicles (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. 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, 2023, Suncor applies a carbon price of $65 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.

<u>International Climate Change Agreements</u>

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.

<u>Canadian Federal GHG and Fuel Regulations</u>

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, in 2018 the federal government introduced 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 CO2e in 2019 and has been rising by $10 per year to $50 per tonne of CO2e 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 CO2e per year starting in 2023, rising to $170 per tonne of CO2e 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 confirmed: (i) Canada's annual national minimum carbon price increase of $15 per tonne of CO2e 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 Provincial GHG and Fuel Regulations section below.

Under the federal *Impact Assessment Act*, the Strategic Assessment of Climate Change (SACC) 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.

Supporting 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, Quebec and Saskatchewan have renewable fuel mandates equal to or greater than the current federal RFR.

In addition to the GGPPA imposing an economy-wide consumer carbon levy on the use and combustion of fossil fuels, the *Clean Fuel Regulation* (CFR) was enacted by the federal government under CEPA, replacing the RFR, which the government estimates will achieve annual reductions of at least 26.6 Mt of CO_2e emissions by 2030. The CFR Gazette II was released on July 6, 2022. Effective July 1, 2023, the CFR requires reductions in the carbon intensity of gasoline and diesel fuels supplied into Canada. Credits for CFR are generated for blending renewable fuels, reducing GHGs at fossil fuel facilities, facilitating fuel switching in transportation or purchasing CFR compliance credits annually. Additionally, there was an inclusion of conditions that credits cannot be obtained from products exported from Canada. Suncor is in the process of implementing CFR requirements to ensure compliance.

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.

Under Development

On March 16, 2022, Environment and Climate Change Canada (ECCC) released a discussion paper "A Clean Electricity Standard (CES) in Support of a Net-Zero Electricity Sector". The CES is designed to be the regulatory framework to achieve a net zero electricity system in Canada by 2035. This proposed policy creates risk to carbon pricing programs that provide GHG credits for electricity. It is unclear at this point if this is a risk or opportunity for Suncor electricity generation. Consultations amongst stakeholders are ongoing and Gazette I is expected to be released in 2023.

On March 29, 2022, the federal government announced the release of the *2030 Emissions Reduction Plan: Canada's Next Steps for Clean Air and a Strong Economy*. The plan is a sector-by-sector approach for Canada to reach its climate target of cutting GHG emissions by 40%-45% below 2005 levels by 2030 and contains a goal of achieving net-zero GHG emissions by 2050. At that time, the projected contribution from the oil and gas sector for GHG emissions reduction was 31% from 2005 levels, or 42% from a 2019 baseline. As a follow-up to the 2030 Emissions Reduction Plan, on July 18, 2022, the Government of Canada released a discussion paper document titled "Options to Cap and Cut Oil and Gas Sector Greenhouse Gas Emissions to Achieve 2030 Goals and Net-Zero by 2050". This document proposes two options for the oil and gas sector to reduce GHG emissions to a proposed government set 110 Mt target in 2030. Option 1 consists of a new cap-and-trade system regulated under CEPA, and Option 2 is a modification of the current carbon pricing approach under GGPPA. The specific regulatory mechanism of this GHG emission reduction target has not been determined as government consultations are ongoing.

To incentivize decarbonization investment, the federal government is developing an investment tax credit (ITC) for capital invested in carbon capture, utilization, and storage (CCUS). The Federal Budget 2022 proposes a refundable ITC for businesses that incur eligible CCUS expenses. Applicable to Suncor, the ITC would apply to CCUS projects that permanently store captured CO_2 through eligible use, which includes dedicated geological storage. From 2022 to 2030, a 50% ITC for investment in equipment to capture CO_2 is proposed for CCUS projects, with that rate being halved starting in 2031. With Suncor's participation in the Pathways Alliance, with the objective of net-zero emissions from operations by 2050, the ITC is an incentive for CCUS project development. Suncor is working with the government on developing the ITC and other fiscal supports to enable decarbonization investments across company assets.

On October 4, 2022, ECCC released "Draft Guidance for Best-in-Class GHG Emissions Performance by Oil & Gas Projects," which is a component of the SACC supporting the federal impact assessment process. This guidance document outlines information for proponents of oil and gas projects that will undergo a federal impact assessment to demonstrate best-in-class GHG emissions performance on a global scale. This best-in-class GHG emissions performance could be at project startup or proponents could provide a plan for technology implementation over time to achieve global standards. Further guidance is expected to be released in 2023. At this time, Suncor is unable to predict the impact this update will have on its business.

Provincial GHG and Fuel Regulations

Alberta

Oil Sands Emissions Limit Act

The *Oil Sands Emissions Limit Act* 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 this legislation 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 Regulation

The *Technology Innovation and Emissions Reduction Implementation Regulation* (TIER), a regulation enacted under Alberta's *Emissions Management and Climate Resilience Act*, is a provincial carbon pricing regulation 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 2022 and 2023. 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 Mine, Firebag, MacKay River, Fort Hills, the Edmonton refinery and Syncrude. Such facilities are required to reduce emissions intensity from their historical performance using facility-specific benchmarks or from the performance of the top facility in a sector using an approved high-performance benchmark. Facilities that outperform the higher of their facility-specific or high-performance benchmark can generate emission performance credits, while facilities that do not meet their emission intensity target can meet compliance obligation through i) use of emissions performance credits that are generated by other regulated facilities; ii) use of Alberta-based emission offsets that are generated by projects that have voluntarily reduced their GHG emissions following an approved quantification protocol; and/or iii) pay into the TIER fund, which is priced at $50 per tonne of CO_2e as of January 1, 2022.

In June 2022, the Alberta government undertook a legislated review of TIER that was mandated to be completed by the end of 2022. The purpose of the review and related engagement was to update policy, review the system design and recommend regulatory changes to the TIER system. The TIER regulations were amended in December 2022. The amendments maintain federal equivalency from 2023 to 2030. The most impactful change is the increased stringency on the benchmark tightening rate on oil sands facilities from 1% to 2% from 2023 to 2028 and 4% from 2029 to 2030. Other notable amendments include sequestration credits and capture recognition tonnes that are established as new instruments that can be used under TIER and also for CFR credits, the increase to annual credit usage limits, and the tightening of electricity benchmarks starting in 2023. Suncor is incorporating these amendments into long-term forecasting and planning.

The carbon price under TIER increased from $50 per tonne of CO_2e in 2022 to $65 per tonne of CO_2e on January 1, 2023.

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 Mine, 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 emission performance credits, or paying the prevailing carbon price. Offset credits can be generated by conducting eligible activities prescribed by provincial protocols.

Federal RFR

The renewable fuel mandate in Alberta is governed by the federal RFR – refer to the Industry Conditions – Climate Change and GHG Emissions – 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 $50 per tonne of CO2e in 2022 to $65 per tonne of CO2e on January 1, 2023.

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 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 litres 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 low-carbon 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 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 switching to lower emission technologies in transportation. Suncor is able to flow through the BC-LCFS costs to consumers. In spring 2022, the Government of British Columbia amended the Greenhouse Gas Reduction (Renewable & Low Carbon Fuel Requirements Regulation) Act to add jet and marine fuel classes. Effective January 1, 2023, the Government of British Columbia amended the Renewable & Low Carbon Fuel Requirements Regulation to increase carbon intensity reduction targets on gasoline and diesels, from 20% by 2030 to 30% by 2030. 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. Zero Emission Vehicle Mandate

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. However, the Government of British Columbia announced on April 1, 2022 that it is looking to advance the schedule to 26% by 2026, 90% by 2030 and 100% by 2035 and has identified required complementary measures.

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. The effective carbon price, shown as a price per volume of fuel, increased from $45 per tonne of CO2e in 2021 to $50 per tonne of CO2e 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 at the time, the Newfoundland and Labrador carbon price in 2021 was $40 per tonne of CO_2e and increased to $50 per tonne of CO_2e in 2022. On November 22, 2022, a decision was made by the Government of Canada to impose the federal carbon pollution pricing system on the province, effective July 1, 2023. This will increase the carbon tax to $65 per tonne of CO_2e.

Offshore production facilities were assigned an annual GHG reduction target of 10% in 2021 and 12% in 2022 below the facility's 2016-2017 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

As of January 1, 2022, the "made in Ontario" GHG Emissions Performance Standards (EPS) superseded and replaced 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, with the exception of a less favourable stringency performance standard for cogeneration technology required to generate credits for the technology at the federal level.

Cleaner Transportation Fuels Regulation

The *Cleaner Transportation Fuels Regulation* under the *Environmental Protection Act* imposes renewable content in gasoline and diesel 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 to $50 per tonne of CO_2e in 2022, with another increase expected in 2023 to $65 per tonne of CO_2e.

Carbon Capture and Storage Regulations

The Ontario government recently signaled that they are interested in drafting legislation to enable carbon capture and storage activities in the province. The design of the regulations is slated to take place with stakeholder input over the Spring and Fall of 2023.

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.

In August 2022, the Government of Quebec published the final regulation on its cap-and-trade system for the 2024-2030 compliance period. The changes include an annual decline of the facility-specific emissions cap of 2-4%, depending on the sector, compared to the current 1%. The cap decline for Suncor's major industrial sites in the province will be around 2.6% for the next 10 years. The additional funds collected from the increased compliance costs will 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 to 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.

On January 1, 2023, the *Regulation Respecting the Integration of Low Carbon-Intensity Fuel Content into Gasoline and Diesel Fuel* came into effect. The regulation requires integration of low-carbon-intensity fuel content of 10% volume in gasoline and 3% in diesel, increasing to 15% volume in gasoline and 10% in diesel by 2030.

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 2023.

The impact on Suncor, including its Commerce City refinery, is not clear 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, 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. Due to political uncertainty, the extent of these initiatives being implemented is not clear at this time. 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

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)	2021	2022[3]	2023 (Estimate)
Oil Sands[1]	52.5	96.8	182.3
Exploration and Production	nil	nil	0.7
Refining and Marketing[2]	13.9	20.1	27.4

(1) Compliance costs for Suncor are increasing under TIER due to the increase in stringency of the facility benchmarks and rise in prevailing carbon prices. Refer to the TIER section above. A portion of the 2023 costs is estimated based on Fort Hills working interest of 68.76%, an increase from 54.11% in 2021 and 2022.

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

(3) A portion of 2022 costs is 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

The Lower Athabasca Regional Plan (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 the 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, the 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 to date 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 Mining 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. 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 develop oil sands water release guidance. In addition, ECCC's work to meet its 2025 timeline for development of the federal Oil Sands Mine Effluent Regulation (OSMER) is progressing. If implemented, OSMER will help enable oil sands companies to return treated mine water to the Athabasca River.

Air Quality Regulations

Air quality in Suncor's operating areas is an increasing focus and has resulted in the introduction and/or update of policies and regulations of air pollutants, odours and health standards to drive performance improvement. Overall, regulators are moving toward setting new, more stringent limits that often require updating or replacing equipment, as well as 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) – The Canadian Council of Ministers of the Environment, with the exception of Quebec, have implemented the 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), ground-level ozone, NO_2 and SO_2. 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, adhere to CAAQS. The Montreal refinery adheres to Montreal air quality regulation (CMM regulation 90). 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). Suncor currently has several NO_2 and SO_2 emissions reductions projects underway to mitigate the risk of potentially exceeding the CAAQS limits.
- 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. AAAQOs are becoming increasingly stringent, with scientific evidence and knowledge showing that health and environmental effects occur at low ambient air concentrations. 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 both have 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. Environment Canada acknowledges that the upstream oil and gas sector is on track to achieve the 2025 methane reduction target. However, in support of the Global Methane Pledge, Canada committed to reducing oil and gas sector methane emissions by at least 75% below the 2012 level by 2030. Accordingly, ECCC published a draft regulatory framework on November 12, 2022, for 30-day public consultation. Industry associations are actively engaged with ECCC in developing a policy that will effectively attain methane reductions while being practical, efficient to implement and manageable for regulatory bodies and industry. 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)* came into effect on January 1, 2020, with additional parts of the regulation impacting the oil and gas industry coming into effect in January 2022 and 2023. This regulation limits 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* regulation was published in

February 2022. This regulation requires SO_2 emissions reductions from the Sarnia refinery, under normal operation as well as under 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 reductions.

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 (CDPHE) 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 policies and regulations of air pollutants, odours and health standards to drive performance improvement. Overall, regulators are moving toward setting new, more stringent limits that often require updating or replacing equipment, as well as 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 North American Industry Classification System, requires the facilities to conduct real-time fenceline monitoring for covered air toxics, and requires the CDPHE 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.
- *Colorado House Bill 21-1266 (Concerning Efforts to Redress the Effects of Environmental Injustice on Disproportionately Impacted Communities)* – This bill, which was signed into law in 2021, requires, among other things, that the Colorado Air Quality Control Commission (Commission) adopt rules regarding enhanced air modeling and air monitoring in connection with certain permit applications for new and modified stationary sources located in disproportionately impacted communities. The Commission may also consider adopting requirements for enhanced air monitoring of existing sources. The rulemaking is scheduled to be conducted in 2023, and may impose new requirements on the Commerce City refinery.
- Colorado *House Bill 22-1244 (Public Protections from Toxic Air Contaminants)* – This bill was signed into law in 2022 and aims to protect public health and the environment. The bill requires the development of an annual air toxics emissions inventory, beginning in 2024. The CDPHE will develop a monitoring program by January 2024 to determine the concentration of toxic air contaminants. Beginning in July 2027, when applying for a new or modified air pollution permit, the owner of source will be required to submit an analysis of the impacts of the stationary source's toxic air contaminant emissions. In addition, to protect public health and the environment, the CDPHE may reopen any existing air pollution permit and require a decrease or a cessation of the applicable emissions over the shortest practicable time until the emissions no longer contribute to concentrations in excess of a health-based standard. The House Bill also requires the CDPHE to develop emission control regulations by April 30, 2026. The implementation of this bill will increase reporting requirements for Suncor's Commerce City refinery due to the need to develop the annual toxics emission inventory.
- Colorado *House Bill 21-1303 (Global Warming Potential for Public Project Materials)* – This bill was signed into law in July 2021 and requires the Colorado Office of the State Architect (vertical construction) and Colorado Department of Transportation (horizontal construction) to establish maximum acceptable global warming potentials (based on the industry average of global warming potential emissions) for various materials, including asphalt. By January 1, 2026 (2025 for horizontal construction including roads), and every four years thereafter, the Office of the State Architect will be required to review and adjust the global warming potential for each material listed in the bill (which includes asphalt). Environmental Product Declarations will be required from a vendor for any government contract. A contractor will be required to provide an environmental product declaration prior to the commencement of any work. The implementation of this bill may negatively impact Suncor if it is determined that its asphalt products exceed the maximum acceptable global warming potential.
- 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 by 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 by 2028 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 three plants in the Commerce City refinery. In 2022, the Plant 2 Title V permit was issued by the CDPHE. New requirements under this permit include annual air emissions inventory, development of a public-facing continuous emissions monitoring website and a quarterly community report detailing all air emissions exceedances. Plants 1 and 3 are undergoing permit renewal applications which are expected to be issued in 2023.

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. 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. Proponents can fulfil their replacement obligations through a combination of options: replacing at a ratio determined by wetland value from 1:1 to 8:1; paying into the replacement in lieu program; or purchasing available credits from a third-party wetland bank. Wetland replacement costs are expected to 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.

The fifteenth conference of the parties to the UN Convention on Biodiversity (COP15), held in December 2022, led to the ratification of the Kunming-Montreal Global Biodiversity Framework (GBF). The GBF includes four goals and 23 targets to safeguard nature by halting and reversing biodiversity loss, putting nature on a path to recovery by 2050. Key global targets include commitments to the restoration of degraded ecosystems; conservation and protection of land and water; disclosure of risks, impacts and dependencies along the operations, supply/value chains and portfolios for large and transnational companies; and the elimination, phase-out or reform of incentives, including subsidies, that are harmful to biodiversity. As a signatory to the agreement, Canada will develop a National Biodiversity Strategy and Action Plan to meet the goals and targets of the GBF. This will create an emphasis on positive actions for nature related to mitigation, restoration, reclamation and disclosure that could influence Suncor's operations and/or create potential limitations due to protected and conserved area targets. Suncor will work with the governments of Alberta and Canada to understand the role and expectations of business in meeting the goals and targets of the GBF.

Dam Integrity

The Government of Alberta has a rigorous and stringent regulatory system to manage dams within the province. Suncor's internal programs aim to provide compliance and additional oversight in accordance with industry-leading guidelines. The Mining Association of Canada's (MAC) *Guide to the 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. At the international level, the *Global Industry Standard on Tailings Management* (GISTM) provides principles of practice for all new dams for the purpose of raising the level of diligence for tailings dams around the world, with particular attention to old and deteriorating dams. 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.

Reclamation

Suncor is committed to surface reclamation and remediation of lands affected by its operations. The Government of Alberta's Mine Financial Security Program (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. In 2022, a review of MFSP was conducted by the Government of Alberta with expected revisions to the MFSP to be identified in 2023 and applied to the 2024 MFSP filing.

Suncor is 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). In 2022, updates to the Suncor Base Plant and Fort Hills tailings management plans were submitted.

Another component identified in the TMF is integrated water management. In order to support successful closure and reclamation, water quantity must be reduced, and quality must be managed. The Alberta government has been working to develop provincial water release policy guidance. The five-year review for the TMF under LARP could start in 2023 and result in changes to tailings management requirements.

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 $13.2 million for 2022, which will be paid in early 2023. 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 Suncor and the oil sands industry. In 2012, Suncor was a founding member of the Canada's Oil Sands Innovation Alliance (COSIA) with a vision for collaborative action and innovation to enable responsible and sustainable growth of Canada's oil sands while delivering accelerated improvement in environmental performance. Created in 2013, Suncor was a member of the Oil Sands Community Alliance (OSCA) whose purpose was to pursue innovative solutions to build thriving communities and enable responsible oil sands growth through a collaborate approach and engagement amongst stakeholders including municipalities, government, and industry. In 2021, Suncor was a founding member of the Oil Sands Pathways to Net Zero Alliance, an alliance of six companies accounting for 95 percent of oil sands production, committing to work together on an ambitious plan to reduce GHG emissions from oil sands production with the goal of achieving net zero GHG emissions by 2050.

On June 15, 2022, Canada's major oil sands producers announced the combination of three existing industry groups, with Suncor a member of each, focused on innovation and sustainable development into a single organization called the Pathways Alliance. This new organization incorporates the Oil Sands Pathways to Net Zero Alliance, OSCA and COSIA. Subsequent to 2022, the Pathways Alliance was awarded exploratory rights from the Government of Alberta for the proposed carbon capture and storage hub to safely and permanently store CO2 captured from more than 20 oil sands facilities in northern Alberta.

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.

Risk Factors

A discussion of Suncor's risk factors can be found in the "Risk Factors" section in Suncor's annual 2022 MD&A, which section is incorporated by reference herein and available on the Company's SEDAR profile at www.sedar.com.

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. Dividends are paid subject to applicable law, if, as and when declared by the Board.

Suncor paid the following common share dividends over the last three years ended December 31:

($ per share)	Year	Q4	Q3	Q2	Q1
2022	**1.88**	**0.52**	**0.47**	**0.47**	**0.42**
2021	1.05	0.42	0.21	0.21	0.21
2020	1.10	0.21	0.21	0.21	0.47

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, 2022, there were 1,337,470,739 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. Pursuant to the *Petro-Canada Public Participation Act*, 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 March 6, 2023. 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	Outlook	Canadian Commercial Paper Program	U.S. Commercial Paper Program
S&P Global Ratings (S&P)	BBB	Negative	Not rated	A-2
DBRS Morningstar (DBRS)	A (low)	Stable	R-1 (low)	Not rated
Moody's Investors Service (Moody's)	Baa1	Stable	Not rated	P-2
Fitch Ratings (Fitch)	BBB+	Stable	Not rated	F-1

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 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 the 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.

Fitch's long-term credit ratings are on a rating scale that ranges from AAA to BBB (investment grade) and BB to D (speculative grade), which represents the range from highest to lowest quality of such securities rated. The terms "investment grade" and "speculative grade" are market conventions and do not imply any recommendation or endorsement of a specific security for investment purposes. A rating of BBB+ is within the fourth highest of 11 categories and indicates that expectations of default risk are currently low. The capacity for payment of financial commitments is considered adequate, but adverse business or economic conditions are more likely to impair this capacity. The modifiers "+" or "-" may be appended to a rating to denote relative status within major rating categories. A Fitch rating outlook indicates the direction a rating is likely to move over a one to two-year period, with rating outlooks falling into four categories: "Positive", "Negative", "Stable" or "Evolving". Rating outlooks reflect financial or other trends that have not yet reached, or have not been sustained at, a level that would trigger a rating action, but which may do so if such trends continue. Positive or Negative outlooks do not imply that a rating change is inevitable and similarly, ratings with Stable outlooks can be raised or lowered without prior revision of the outlook. Where the fundamental trend has strong, conflicting elements of both positive and negative, the rating outlook may be described as Evolving. A Positive Rating Outlook indicates an upward trend on the rating scale. A short-term issuer or obligation rating is based in all cases on the short-term vulnerability to default of the rated entity and relates to the capacity to meet financial obligations in accordance with the documentation governing the relevant obligation. A rating of F-1 for commercial paper is the highest of seven rating categories for short-term debt issuers. Issuers rated F-1 have the strongest capacity for timely payment of financial commitments relative to other issuers or obligations in the same country. Where liquidity profile is particularly strong, a "+" is added to the assigned rating.

Suncor has paid each of S&P, DBRS, Moody's and Fitch their customary fees in connection with the provision of the above ratings. Suncor has not made any payments to S&P, DBRS, Moody's or Fitch 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, 2022 are as follows:

	Price Range (Cdn$)		Trading Volume
	High	Low	(000s)
2022			
January	36.69	32.08	195,702
February	38.78	35.79	247,193
March	43.12	37.43	328,779
April	47.89	38.74	153,622
May	53.17	43.13	218,794
June	53.62	42.28	250,108
July	46.72	37.75	131,870
August	45.80	37.98	304,143
September	43.03	36.39	262,597
October	47.31	40.34	136,254
November	50.37	44.16	268,114
December	44.66	40.10	273,371

For information in respect of options to purchase common shares of Suncor and common shares issued upon the exercise of options, see Note 26 to the 2022 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
Ian R. Ashby(1)(2) California, U.S.	Director since 2022 Independent	Ian Ashby is the former president of BHP Billiton's iron ore customer sector group. Mr. Ashby has almost 40 years of experience in the mining industry, including 25 years in a wide variety of roles with BHP Billiton in its iron ore, base metals and gold businesses in Australia, the U.S., and Chile, as well as project roles in the corporate office, ultimately leading the company's iron ore business. Since retiring from BHP Billiton in 2012, Mr. Ashby has taken on a number of advisory and board roles with other mining and related organizations. He currently serves as an independent director on the boards of Anglo American plc and IAMGOLD Corporation. He has served as a director on the boards of New World Resources PLC, Genco Shipping & Trading, Nevsun Resources Ltd., and Alderon Iron Ore Corp. He has also served in an advisory capacity with Apollo Global Management and Temasek. Mr. Ashby holds a bachelor of engineering (mining) degree from the University of Melbourne in Australia.
Patricia M. Bedient(2)(3) 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 Oregon State University board of trustees, and the University of Washington Foster School of Business advisory board. She achieved national recognition in 2012 when the *Wall Street Journal* named her one of the Top 25 CFOs in the United States. She is a member of the American Institute of CPAs and the Washington Society of CPAs. Ms. Bedient received her bachelor's degree in business administration, with concentrations in finance and accounting, from Oregon State University in 1975.
Russell Girling(1)(4) 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 and the U.S. Business Roundtable, and he 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.

Name and Jurisdiction of Residence	Period Served and Independence	Biography
Jean Paul Gladu[(3)(4)] 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 M. Houston[(1)(4)] Texas, U.S.	Director since 2018 Independent	Dennis Houston served as executive vice president of ExxonMobil Refining & Supply Company, chair and president of ExxonMobil Sales & Supply LLC and chair 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.

Name and Jurisdiction of Residence	Period Served and Independence	Biography
Brian MacDonald[2][3] Florida, U.S.	Director since 2018 Independent	Brian MacDonald is the 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. 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 chair, 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.
Lorraine Mitchelmore[1][2] 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 Alberta Investment Management Corporation 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 an MBA with distinction from Kingston Business School in London, England.

Name and Jurisdiction of Residence	Period Served and Independence	Biography
Christopher R. Seasons(1)(4) Alberta, Canada	Director since 2022 Independent	Christopher (Chris) Seasons is a professional engineer with more than 30 years of domestic and international experience in the upstream oil and gas industry. He is currently partner at ARC Financial Corporation, an energy-focused private equity firm. From 2004 until his retirement in June 2014, he served as president of Devon Canada, a subsidiary of Oklahoma-based Devon Energy. Mr. Seasons has long been active in the Calgary community with several not-for-profit organizations including the Canadian Association of Petroleum Producers (former chair and head of numerous committees), the Alberta Children's Hospital Foundation (past chair and current board member), and the United Way Calgary and Area (past co-chair of the annual campaign and current board member). Mr. Seasons graduated from Queen's University with a bachelor of science degree in chemical engineering.
M. Jacqueline Sheppard(3)(4) Alberta, Canada	Director since 2022 Independent	Jacqueline (Jackie) Sheppard is the former executive vice president, Corporate & Legal, of Talisman Energy Inc. Ms. Sheppard is chair of the board of Emera Inc. and serves on the board of ARC Resources Ltd. She previously chaired the board of the Research & Development Corporation of the Province of Newfoundland and Labrador, a provincial crown corporation, and has served on several boards such as Pacific NorthWest LNG, Alberta Investment Management Corporation, Seven Generations Energy Ltd. and Cairn Energy PLC. Ms. Sheppard was also a founder and lead director of Black Swan Energy Inc., an Alberta upstream energy company that was private-equity financed and sold to Tourmaline Oil Corp. Ms. Sheppard was named one of Canada's top 100 most powerful women by the Women's Executive Network (WXN) and the National Post from 2002-2007 and has been admitted to the Network's Hall of Fame. In honour of her exceptional merit and integrity in the legal profession, Jackie was appointed Queen's Counsel in 2008. Ms. Sheppard is a Fellow of Institute of Corporate Directors, Canada's preeminent distinction for directors, a Rhodes Scholar, and received an honours degree in jurisprudence, bachelor of arts and master of arts from Oxford University. She earned a bachelor of law degree (honours) from McGill University, and a bachelor of arts degree from Memorial University of Newfoundland.
Eira M. Thomas(3)(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.

Name and Jurisdiction of Residence	Period Served and Independence	Biography
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) Environment, Health, Safety and Sustainable Development Committee

(2) Audit Committee

(3) Governance Committee

(4) Human Resources and Compensation Committee

Executive Officers

The following individuals are the executive officers of Suncor as at February 27, 2023:

Name	Jurisdiction of Residence	Office
Kris Smith(1)	Alberta, Canada	Interim President and Chief Executive Officer
Alister Cowan(1)	Alberta, Canada	Chief Financial Officer
Bruno Francoeur	Alberta, Canada	Executive Vice President, Business & Operations
Jacqueline Moore	Alberta, Canada	Chief Legal Officer and General Counsel
Paul Gardner	Alberta, Canada	Chief People Officer
Shelley Powell	Alberta, Canada	Senior Vice President, E&P and In Situ
Arlene Strom	Alberta, Canada	Chief Sustainability Officer
Peter Zebedee	Alberta, Canada	Executive Vice President, Mining & Upgrading

(1) Effective April 3, 2023, Rich Kruger will be appointed President and Chief Executive Officer. Effective May 9, 2023, Kris Smith will assume the role of Chief Financial Officer and Executive Vice President of Corporate Development and Alister Cowan, the current Chief Financial Officer, plans to retire at the end of 2023.

All executive officers have held positions with Suncor over the past five years, with the exception of Peter Zebedee who, immediately prior to joining Suncor in 2022, was CEO of LNG Canada.

As at February 27, 2023, the directors and executive officers of Suncor as a group beneficially owned, or controlled or directed, directly or indirectly, 406,625 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 27, 2023, is 1,163,759 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 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.

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. Ashby, Mr. MacDonald and Ms. Mitchelmore. All members are independent and financially literate. The education and experience of each member that has led to the determination of financial literacy is described in the Directors and Executive Officers section of this AIF.

For the purpose of making appointments to the company's Audit Committee, and in addition to the independence requirements, all directors nominated to the Audit Committee must meet the test of financial literacy as determined in the judgment of the Board of Directors. Also, at least one director so nominated must meet the requirements of being an Audit Committee Financial Expert (as defined below) as determined in the judgment of the Board of Directors. The Audit Committee Financial Experts on the Audit Committee are Ms. Bedient and Mr. MacDonald.

Financial Literacy

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

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

Audit Committee Financial Expert

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

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

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

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

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

(e) an understanding of audit committee functions.

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

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

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

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

(d) other relevant experience.

Audit Committee Pre-Approval Policies for Non-Audit Services

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

Fees Paid to Auditors

Fees paid or payable to the company's auditors, KPMG LLP (Calgary, Canada), in 2022 and 2021 are as follows:

($ thousands)	2022	2021
Audit fees(1)	**7,406**	6,441
Audit-related fees	**835**	465
All other fees	**241**	—
Total	**8,482**	6,906

(1) 2021 audit fees have been restated to include $0.7 million related to Syncrude audit services and reflect Suncor assuming the role of operator on September 30, 2021.

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 advisory services around ESG. 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, 2022, 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, 2022, (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, 2022.

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, 2022, 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, (KPMG). 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 2023 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 2022 audited Consolidated Financial Statements and in the annual 2022 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:

- *Expectations about the West White Rose Project, including the expectation that it would extend the life of the existing White Rose assets and the expectation that production will commence in the first half of 2026 and will extend the production life of the White Rose field, providing long-term value for the company;*
- *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 ambitious near-term goals of reducing emissions across its value chain and the plans and areas of focus that Suncor has to achieve these objectives and goals;*
- *Expectations about Terra Nova and the ALE Project, including the expectation that the ALE Project will extend production life of the Terra Nova field by approximately 10 years and provide many benefits to the Newfoundland and Labrador and Canadian economies in the form of taxes, royalties and employment and that the FPSO will return to production in the second quarter of 2023;*
- *Statements about Suncor's coke-fired boiler replacement program, including the expectation that it will provide 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 in late 2024;*
- *Statements regarding the Pathways 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 regarding the sale of the company's U.K. E&P portfolio for gross proceeds of approximately $1.2 billion, including a contingent consideration of approximately $338 million and the expectation that the sale will close in mid-2023;*
- *Expectations regarding the MLX-W and MLX-E programs, including that the MLX-E program will follow MLX-W development if economic conditions remain suitable, 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 that MLX-W will achieve first oil in late 2025;*
- *Statements regarding the Fort Hills 3-year mine improvement plan including the expected impacts to production rates and operating costs;*
- *Suncor's expectation that the Sunbridge power asset will be fully decommissioned in 2023;*
- *The estimated cost of Suncor's remaining exploration work program commitment in Libya at December 31, 2022, 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;*
- *The potential for both development opportunities that may support future mining operations including interests in Base Mine Extension and Audet, as well as 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 dominated recovery process and, non-aqueous extraction;*
- *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 2023, 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;*
- *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, regulatory permits 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 socioeconomic 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 and the company's annual 2022 MD&A including under the heading Risk Factors, 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 under GAAP 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, 2022 and dated March 6, 2023.

Schedule "A"
Audit Committee Mandate

The Audit Committee

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

Objectives

The Audit Committee assists the Board by:

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

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

Constitution

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

Functions and Responsibilities

The Audit Committee has the following functions and responsibilities:

Internal Controls

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

External and Internal Auditors

7. Evaluate the performance of the external auditors and initiate and approve the engagement or termination of the external auditors, subject to shareholder approval as required by applicable law.
8. Review the audit scope and approach of the external auditors, and approve their terms of engagement and fees.
9. Review any relationships or services that may impact the objectivity and independence of the external auditor, including annual review of the auditor's written statement of all relationships between the auditor (including its affiliates) and the Corporation; review and approve all engagements for non-audit services to be provided by external auditors or their affiliates.
10. Review the external auditor's quality control procedures including any material issues raised by the most recent quality control review or peer review and any issues raised by a government authority or professional authority investigation of the external auditor, providing details on actions taken by the firm to address such issues.
11. Approve the appointment or termination of the VP Enterprise Risk and Audit, approve annually the performance assessment and resulting compensation of the VP Enterprise Risk & Audit as provided by the Chief Financial Officer. Periodically review the performance and effectiveness of the Internal Audit function including conformance with The Institute of Internal Auditors' International Standards for the Professional Practice of Internal Auditing and the Code of Ethics.

12. Approve the Internal Audit Department Charter, the annual Internal Audit schedule, as well as the Internal Audit budget and resource plan. Review the plans, activities, organizational structure, resource capacity and qualifications of the Internal Auditors, and monitor the department's independence.

13. Provide direct and unrestricted access by management, the Internal Auditors and the external auditors to the Board of Directors.

Financial Reporting and other Public Disclosure

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

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

16. Review and approve the Corporation's interim consolidated financial statements and accompanying management's discussion and analysis ("MD&A"). Review and make recommendations to the Board of Directors on approval of the Corporation's annual audited financial statements and MD&A, Annual Information Form and Form 40-F. Review other material annual and quarterly disclosure documents or regulatory filings containing or accompanying audited or unaudited financial information.

17. Authorize any changes to the categories of documents and information requiring audit committee review or approval prior to external disclosure, as set out in the Corporation's policy on external communication and disclosure of material information.

18. Review any change in the Corporation's accounting policies.

19. Review with legal counsel any legal matters having a significant impact on the financial reports.

Oil and Gas Reserves

20. Review with reasonable frequency Suncor's procedures for:

(A) the disclosure, in accordance with applicable law, of information with respect to Suncor's oil and gas activities including procedures for complying with applicable disclosure requirements;

(B) providing information to the qualified reserves evaluators ("Evaluators") engaged annually by Suncor to evaluate Suncor's reserves data for the purpose of public disclosure of such data in accordance with applicable law.

21. Annually approve the appointment and terms of engagement of the Evaluators, including the qualifications and independence of the Evaluators; review and approve any proposed change in the appointment of the Evaluators, and the reasons for such proposed change including whether there have been disputes between the Evaluators and management.

22. Annually review Suncor's reserves data and the report of the Evaluators thereon; annually review and make recommendations to the Board of Directors on the approval of (i) the content and filing by the Company of a statement of reserves data ("Statement") and the report thereon of management and the directors to be included in or filed with the Statement, and (ii) the filing of the report of the Evaluators to be included in or filed with the Statement, all in accordance with applicable law.

Risk Management

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

Pension Plan

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

Security

25. Review on a summary basis any significant physical security management and strategies to address such risks.

Other Matters

26. Conduct any independent investigations into any matters which come under its scope of responsibilities.

27. Review any recommended appointees to the office of Chief Financial Officer.

28. Review and/or approve other financial matters delegated specifically to it by the Board of Directors.

Reporting to the Board

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

Approved by resolution of the Board of Directors on November 14, 2017

Schedule "B" – Suncor Energy Inc. Policy and Procedures for Pre-Approval of Audit and Non-Audit Services

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

I. Statement of Policy

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

II. Responsibility

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

III. Definitions

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

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

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

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

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

(iii) Attest services required by statute or regulation;

(iv) Internal control reviews; and

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

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

"Audit-related services" include:

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

(ii) due diligence related to mergers and acquisitions;

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

(iv) internal control reviews;

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

(vi) consultations regarding financial accounting and reporting standards.

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

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

(d) "All other services" consist of any other work that is neither an Audit service, nor an Audit-Related service nor a Tax service, the provision of which by the independent auditor is not expressly prohibited by Rule 2-01(c)(7) of Regulation S-X under the Securities and Exchange Act of 1934, as amended. (See Appendix A for a summary of the prohibited services.)

IV. General Policy

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

- All services to be provided by the independent auditor will require specific pre-approval by the Audit Committee. The Audit Committee will not approve engaging the independent auditor for services which can reasonably be classified as "tax services" or "all other services" unless a compelling business case can be made for retaining the independent auditor instead of another service provider.
- The Audit Committee will not provide pre-approval for services to be provided in excess of twelve months from the date of the pre-approval, unless the Audit Committee specifically provides for a different period.
- The Audit Committee has delegated authority to pre-approve services with an estimated cost not exceeding $100,000 in accordance with this Policy to the Chairman

of the Audit Committee. The delegate member of the Audit Committee must report any pre-approval decision to the Audit Committee at its next meeting.

- The Chairman of the Audit Committee may delegate his authority to pre-approve services to another sitting member of the Audit Committee provided that the recipient has also been delegated the authority to act as Chairman of the Audit Committee in the Chairman's absence. A resolution of the Audit Committee is required to evidence the Chairman's delegation of authority to another Audit Committee member under this policy.
- The Audit Committee will, from time to time, but no less than annually, review and pre-approve the services that may be provided by the independent auditor.
- The Audit Committee must establish pre-approval fee levels for services provided by the independent auditor on an annual basis. On at least a quarterly basis, the Audit Committee will be provided with a detailed summary of fees paid to the independent auditor and the nature of the services provided, and a forecast of fees and services that are expected to be provided during the remainder of the fiscal year.
- The Audit Committee will **not** approve engaging the independent auditor to provide any prohibited non-audit services as set forth in Appendix A.
- The Audit Committee shall evidence their pre-approval for services to be provided by the independent auditor as follows:

  (a) In situations where the Chairman of the Audit Committee pre-approves work under his delegation of authority, the Chairman will evidence his pre-approval by signing and dating the pre-approval request form, attached as Appendix B. If it is not practicable for the Chairman to complete the form and transmit it to the Company prior to engagement of the independent audit, the Chairman may provide verbal or email approval of the engagement, followed up by completion of the request form at the first practical opportunity.

  (b) In all other situations, a resolution of the Audit Committee is required.

- All audit and non-audit services to be provided by the independent auditors shall be provided pursuant to an engagement letter that shall:

  (a) be in writing and signed by the auditors;

  (b) specify the particular services to be provided;

  (c) specify the period in which the services will be performed;

  (d) specify the estimated total fees to be paid, which shall not exceed the estimated total fees approved by the Audit Committee pursuant to these procedures, prior to application of the 10% overrun;

  (e) include a confirmation by the auditors that the services are not within a category of services the provision of which would impair their independence under applicable law and Canadian and U.S. generally accepted accounting standards.

- The Audit Committee pre-approval permits an overrun of fees pertaining to a particular engagement of no greater than 10% of the estimate identified in the associated engagement letter. The intent of the overrun authorization is to ensure on an interim basis only, that services can continue pending a review of the fee estimate, and, if required, further Audit Committee approval of the overrun. If an overrun is expected to exceed the 10% threshold, as soon as the overrun is identified, the Audit Committee or its designate must be notified and an additional pre-approval obtained prior to the engagement continuing.

V. Responsibilities of External Auditors

To support the independence process, the independent auditors will:

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

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

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

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

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

In addition, the external auditors will:

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

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

VI. Disclosures

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

Approved and Accepted April 28, 2004

Appendix A – Prohibited Non-Audit Services

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

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

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

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

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

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

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

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

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

Human resources. Any of the following:

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

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

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

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

Appendix B – Pre-Approval Request Form

NATURE OF WORK	ESTIMATED FEES (Cdn$)
Total	

Date

Signature

Schedule "C" – Form 51-101F2 Report on Reserves Data by Independent Qualified Reserves Evaluator or Auditor

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

1. We have evaluated the Company's reserves data as at December 31, 2022. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2022, 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, 2022, 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, 2022	Oil Sands In Situ, Canada	—	28,460	—	28,460
GLJ Ltd.	December 31, 2022	Oil Sands Mining, Canada	—	32,601	—	32,601
GLJ Ltd.	December 31, 2022	East Coast Canada, Newfoundland Offshore, Canada	—	7,827	—	7,827
GLJ Ltd.	December 31, 2022	Offshore, United Kingdom	—	2,452	—	2,452
			—	71,340	—	71,340

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, March 6, 2023

"Tim R. Freeborn"

Tim R. Freeborn, P.Eng.
Vice President

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.

"*Kris P. Smith*"

KRIS P. SMITH
Interim 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

March 6, 2023

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