ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2020

February 8, 2021

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NOTE TO READER

Unless otherwise indicated, in this Annual Information Form ("**AIF**"), the terms "**Husky**" and the "**Company**" mean Husky Energy Inc. and its subsidiaries and partnership interests on a consolidated basis, including information with respect to predecessor corporations.

Unless otherwise indicated, the information contained in this AIF is presented as at or for the year ended December 31, 2020, and all financial information included and incorporated by reference in this AIF is determined using International Financial Reporting Standards ("**IFRS**"), as issued by the International Accounting Standards Board.

Except where otherwise indicated, all dollar amounts stated in this AIF are in Canadian dollars.

This AIF is for the year ended December 31, 2020, and is in respect of Husky and its consolidated entities and considers the completion of the Cenovus Transaction (as defined below).

See also "Reader Advisories" on page 99 of this AIF.

ABBREVIATIONS AND GLOSSARY OF TERMS

When used in this AIF, the following terms have the meanings indicated:

Units of Measure	
bbl	barrel
bbls/day	barrels per calendar day
bcf	billion cubic feet
boe	barrels of oil equivalent
boe/day	barrels of oil equivalent per calendar day
GJ	gigajoule
long ton/day	imperial measurement of a metric tonne per calendar day
mbbls	thousand barrels
mbbls/day	thousand barrels per calendar day
mboe	thousand barrels of oil equivalent
mboe/day	thousand barrels of oil equivalent per calendar day
mcf	thousand cubic feet
mcf/day	thousand cubic feet per calendar day
MJ	megajoule
mmbbls	million barrels
mmboe	million barrels of oil equivalent
mmbtu	million British thermal units
mmcf	million cubic feet
mmcf/day	million cubic feet per calendar day

abandonment and reclamation costs
All costs associated with the process of restoring the Company's properties that have been disturbed by oil and gas activities to a standard imposed by applicable government or regulatory authorities, including costs associated with the retirement of upstream and downstream assets which consist primarily of plugging and abandoning wells, abandoning surface and subsea plant, equipment and facilities, and restoring land.

ABCA
Business Corporations Act (Alberta).

API gravity
Measure of oil density or specific gravity used in the petroleum industry. The API scale expresses density such that the greater the density of the petroleum, the lower the degree of API gravity.

Asphalt Refinery
The asphalt refinery owned by the Company and located in Lloydminster, Alberta.

Audit Committee
The Audit Committee of the Board.

barrel
A unit of volume equal to 42 U.S. gallons.

bitumen
A naturally occurring solid or semi-solid hydrocarbon, consisting mainly of heavier hydrocarbons with a viscosity greater than 10,000 millipascal-seconds or 10,000 centipoise measured at the hydrocarbon's original temperature in the reservoir and at atmospheric pressure on a gas-free basis, and that is not primarily recoverable at economic rates through a well without the implementation of enhanced recovery methods.

Board
The Board of Directors of the Company.

Board Committees
Collectively, the Audit Committee, the Compensation Committee, the Corporate Governance Committee and the HS&E Committee.

BP-Husky Toledo Refinery
The crude oil refinery owned 50% by the Company and 50% by BP Corporation North America Inc. and located in Toledo, Ohio.

Cenovus
Cenovus Energy Inc.

CHOPS
Cold heavy oil production with sand.

C-NLOPB
Canada-Newfoundland Offshore Petroleum Board

CNOOC
CNOOC Limited

CO_2
Carbon dioxide.

CO_2e
Carbon dioxide equivalent.

Compensation Committee
The Compensation Committee of the Board.

conventional natural gas
Natural gas that has been generated elsewhere and has migrated as a result of hydrodynamic forces and is trapped in discrete accumulations by seals that may be formed by localized structural, depositional or erosional geological features.

Corporate Governance Committee
The Corporate Governance Committee of the Board.

DBRS
Dominion Bond Rating Services Limited

development well
A well drilled within the proved area of an oil and gas reservoir to the depth of a stratigraphic horizon known to be productive.

diluent
A lighter gravity liquid hydrocarbon, usually condensate or synthetic crude oil, added to heavy oil and bitumen to facilitate the transmissibility of the oil through a pipeline.

DSU
A deferred share unit issued under the Company's Share Accumulation Plan for Directors.

enhanced oil recovery or EOR
The increased recovery from a crude oil pool achieved by artificial means or by the application of energy extrinsic to the pool. An artificial means or application includes pressuring, cycling, pressure maintenance or injection to the pool of a substance or form of energy but does not include the injection in a well of a substance or form of energy for the sole purpose of aiding in the lifting of fluids in the well, or stimulation of the reservoir at or near the well by mechanical, chemical, thermal or explosive means.

exploration licence or EL
A licence with respect to the Canadian offshore or the Northwest Territories conferring the right to explore for, and the exclusive right to drill and test for, hydrocarbons and petroleum, the exclusive right to develop the applicable area in order to produce petroleum and, subject to satisfying the requirements for issuance of a production licence and compliance with the terms of the licence and other provisions of the relevant legislation, the exclusive right to obtain a production licence.

exploration well
A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas. Generally, an exploration well is any well that is not a development well, a service well, an extension well, which is a well drilled to extend the limits of a known reservoir, or a stratigraphic test well as those terms are defined herein.

feedstock
Raw materials which are processed into petroleum products.

field
An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both.

FPSO
Floating production, storage and offloading vessel.

GAAP
Generally accepted accounting principles, consistently applied.

GHG
Greenhouse gas.

gross/net acres and gross/net wells
Gross refers to the total number of acres or wells, as the context requires, in which a working interest is owned. Net refers to the sum of the fractional working interests owned by a company.

gross reserves and gross production
A company's working interest share of reserves or production, as the context requires, before deduction of royalties.

GSA
Gas sales agreement.

heavy crude oil
Crude oil with a relative density greater than 10 degrees API gravity and less than or equal to 22.3 degrees API gravity.

high-TAN
A measure of acidity. Crude oils with a high content of naphthenic acids are referred to as high total acid number ("**TAN**") crude oils or high acid crude oil. The TAN value is defined as the milligrams of Potassium Hydroxide required to neutralize the acidic group of one gram of the oil sample. Crude oils in the industry with a TAN value greater than one are referred to as high-TAN crudes.

HMLP
Husky Midstream Limited Partnership.

HS&E
Health, safety and environment.

HS&E Committee
The Health, Safety and Environment Committee of the Board.

light crude oil
Crude oil with a relative density greater than 31.1 degrees API gravity.

Lima Refinery
The crude oil refinery owned by the Company and located in Lima, Ohio.

liquefied petroleum gas
Liquefied propanes and butanes, separately or in mixtures.

medium crude oil
Crude oil with a relative density greater than 22.3 degrees API gravity and less than or equal to 31.1 degrees API gravity.

natural gas
A naturally occurring hydrocarbon gas and other gases.

natural gas liquids or NGL
Those hydrocarbon components recovered from raw natural gas as liquids by processing through extraction plants, or recovered from field separators, scrubbers or other gathering facilities. These liquids include the hydrocarbon components ethane, propane and butane and condensates and combinations thereof.

net revenue
Gross revenue less royalties.

NL
Newfoundland and Labrador.

oil sands
Sands and other rock materials that contain bitumen and all other mineral substances in association therewith.

OPEC
Organization of the Petroleum Exporting Countries.

operating netback
Gross revenue less production, operating and transportation costs and royalties on a per unit basis.

petroleum coke
A carbonaceous solid delivered from oil refinery coker units or other cracking processes.

production licence
Confers, with respect to the portions of the offshore area to which the licence applies, the right to explore for, and the exclusive right to drill and test for, petroleum, the exclusive right to develop those portions of the offshore area in order to produce petroleum, the exclusive right to produce petroleum from those portions of the offshore area and title to the petroleum produced.

production sharing contract or PSC
A contract for the development of resources under which the contractor's costs (investment) are recoverable each year out of the production but with a maximum amount of production that can be applied to the cost recovery in any year.

Scope 1 emissions
Direct emissions from sources that are owned or controlled by the Company, as prescribed by the U.S. Environmental Protection Agency.

Scope 2 emissions
Indirect emissions from sources that are owned or controlled by the Company, as prescribed by the U.S. Environmental Protection Agency.

SEC
United States Securities and Exchange Commission.

SEDAR
System for Electronic Document Analysis and Retrieval.

secondary recovery
Oil or gas recovered by injecting water or gas into the reservoir to force additional oil or gas to the producing wells. Usually, but not necessarily, this is done after the primary recovery phase has passed.

seismic survey
A method by which the physical attributes in the outer rock shell of the earth are determined by measuring, with a seismograph, the rate of transmission of shock waves through the various rock formations.

service well
A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, saltwater disposal, water supply for injection, observation or injection for in-situ combustion.

Significant Discovery Declaration
A discovery indicated by the first well on a geological feature that demonstrates by flow testing the existence of hydrocarbons in that feature and, having regard to geological and engineering factors, suggests the existence of an accumulation of hydrocarbons that has potential for sustained production.

Significant Discovery Licence
The document of "title" by which an interest owner can continue to hold rights to a discovery area while the extent of that discovery is determined and, if it has potential to be brought into commercial production in the future, until commercial development becomes viable. A significant discovery licence is effective from the application date and remains in force for so long as the relevant declaration of significant discovery is in force, or until a production licence is issued for the relevant lands.

spot price
The price for a one-time open market transaction for immediate delivery of a specific quantity of product at a specific location where the commodity is purchased “on the spot” at current market rates.

steam-assisted gravity drainage or SAGD
An enhanced oil recovery method used to produce heavy crude oil and bitumen in-situ. Steam is injected via a horizontal well along a producing formation. The temperature in the formation increases and lowers the viscosity of the crude oil allowing it to fall into a horizontal production well beneath the steam injection well.

stratigraphic test well
A hole drilled to delineate or derisk the geology, and may include the cutting of cores, to aid in exploring and developing for oil and gas and usually drilled without the intent of being completed for production.

sulphur
An element that occurs in natural gas and petroleum.

Superior Refinery
The crude oil refinery owned by the Company and located in Superior, Wisconsin.

synthetic crude oil
A mixture of hydrocarbons derived by upgrading heavy crude oils, including bitumen, through a process that reduces the carbon content and increases the hydrogen content.

thermal
Use of steam injection into the reservoir in order to enable the heavy oil and bitumen to flow to the well bore.

Tidewater
Tidewater Midstream and Infrastructure Ltd.

TSX
Toronto Stock Exchange.

turnaround
Performance of plant or facility maintenance.

Upgrader
The heavy oil upgrading facility owned and operated by the Company and located in Lloydminster, Saskatchewan.

waterflood
One method of secondary recovery in which water is injected into an oil reservoir for the purpose of forcing oil out of the reservoir and into the bore of a producing well.

wellhead
The structure, sometimes called the "Christmas tree", that is positioned on the surface over a well and used to control the flow of oil or gas as it emerges from the subsurface casing head.

working interest
A percentage of ownership in an oil and gas lease granting its owners the right to explore, drill and produce oil and gas from a property.

2-D seismic survey
Two-dimensional seismic imaging uses seismic wave data recorded on one receiver line on the ground, to output a single cross-section of seismic data that is used to detect geologic variations in the subsurface.

3-D seismic survey
Three-dimensional seismic imaging uses seismic wave data recorded simultaneously on a series of parallel receiver lines on the ground, to output a three-dimensional volume of seismic data that is used to detect geologic variations in the subsurface.

2018 U.S. Shelf Prospectus and Registration Statement
The universal short form base shelf prospectus filed by the Company on January 29, 2018 with the Alberta Securities Commission and the related U.S. registration statement (containing such prospectus) filed with the SEC that became effective on January 30, 2018.

2019 Canadian Shelf Prospectus
The universal short form base shelf prospectus filed by the Company on May 1, 2019 with the applicable securities regulators in each of the provinces of Canada.

2020 U.S. Shelf Prospectus and Registration Statement
The universal short form base shelf prospectus filed by the Company on March 3, 2020 with the Alberta Securities Commission and the related U.S. registration statement (containing such prospectus) filed with the SEC that became effective on March 4, 2020.

EXCHANGE RATE INFORMATION

The following table discloses various indicators of the Canadian dollar/U.S. dollar rate of exchange or the cost of a U.S. dollar in Canadian currency for the three years indicated.

	Year ended December 31,		
Exchange Rate Information *(Cdn$ per US$)*	**2020**	2019	2018
Year-end[(1)]	**1.276**	1.297	1.365
Low	**1.272**	1.297	1.228
High	**1.454**	1.359	1.365
Average	**1.340**	1.327	1.296

(1) The year-end exchange rates were quoted by the Thomson Reuters WM/R for the noon rate at the last day of the relevant period. The high, low and average rates were either quoted or calculated within each of the relevant periods.

CORPORATE STRUCTURE

Incorporation and Organization

Husky Energy Inc. was incorporated under the ABCA on June 21, 2000. The Company's articles were amended effective February 28, 2011 to permit the issuance of common shares as payment of stock dividends on the common shares and to authorize preferred shares to be issued in one or more series. The Company's articles were amended: effective March 11, 2011; to create Cumulative Redeemable Preferred Shares, Series 1 (the "Series 1 Preferred Shares") and Cumulative Redeemable Preferred Shares, Series 2 (the "Series 2 Preferred Shares"); effective December 4, 2014; to create Cumulative Redeemable Preferred Shares, Series 3 (the "Series 3 Preferred Shares") and Cumulative Redeemable Preferred Shares, Series 4 (the "Series 4 Preferred Shares"); effective March 9, 2015; to create Cumulative Redeemable Preferred Shares, Series 5 (the "Series 5 Preferred Shares") and Cumulative Redeemable Preferred Shares, Series 6 (the "Series 6 Preferred Shares"); and effective June 15, 2015; to create Cumulative Redeemable Preferred Shares, Series 7 (the "Series 7 Preferred Shares") and Cumulative Redeemable Preferred Shares, Series 8 (the "Series 8 Preferred Shares"). Husky's registered office and head and principal office are located at 707 - 8th Avenue S.W., Calgary, Alberta, T2P 1H5.

Intercorporate Relationships

The following table lists Husky's significant subsidiaries and jointly-controlled entities and their respective places of incorporation, continuance or organization, as the case may be, as at December 31, 2020. All of the entities listed below, except as otherwise indicated, are 100% beneficially owned, or controlled or directed, directly or indirectly, by Husky.

Significant Subsidiaries and Joint Operations[(1)]	Jurisdiction
Husky Oil Operations Limited	Alberta
Husky Energy International Corporation	Alberta
Lima Refining Company	Delaware
Husky Marketing and Supply Company	Delaware
Husky Oil Limited Partnership	Alberta
Husky Canadian Petroleum Marketing Partnership	Alberta
Husky Energy Marketing Partnership	Alberta
Sunrise Oil Sands Partnership (50%)	Alberta
BP-Husky Refining LLC (50%)	Delaware

(1) Principal operating subsidiaries exclusive of intercorporate relationships due to financing related receivables and financing investments.

GENERAL DEVELOPMENT OF HUSKY

Three-year History of Husky

The following is a description of how Husky's business has developed over the last three completed financial years.

2018

On January 17, 2018, the Company announced that it would begin taking steps to suspend operations of the *SeaRose* FPSO and associated production facilities offshore NL to comply with an order received from the C-NLOPB related to an iceberg management incident that occurred in March 2017.

On January 26, 2018, the Company announced that the C-NLOPB had lifted the notice to suspend operations of the *SeaRose* FPSO and associated facilities and that the Company would resume operations.

On March 1, 2018, the Company announced the establishment of a quarterly cash dividend of $0.075 per common share.

On April 26, 2018, a fire occurred at the Superior Refinery and operations were suspended.

On May 18, 2018, the Company announced that it had drilled a successful exploration well on Block 15/33 in the South China Sea, signed two PSCs for Block 22/11 and Block 23/07 in the Beibu Gulf area of the South China Sea and made a discovery at the White Rose A-24 exploration well offshore NL.

On July 26, 2018, the Company announced that the Board had approved an increase in the quarterly cash dividend to $0.125 per common share.

During the third quarter of 2018, the BD Project achieved total daily sales targets of 100 mmcf/day of conventional natural gas (40 mmcf/day Husky working interest) and 6,000 bbls/day of associated NGL (2,400 bbls/day Husky working interest).

On October 2, 2018, the Company announced that it had commenced an unsolicited offer to acquire all of the outstanding common shares of MEG Energy Corp. ("**MEG**").

In October 2018, the Tucker Thermal Project reached nameplate capacity of 30,000 bbls/day.

Also in October 2018, the Rush Lake 2 thermal project achieved first production, with nameplate capacity of 10,000 bbls/day achieved in November 2018.

In November 2018, the Company shut in oil production at the White Rose field due to operational safety concerns resulting from severe weather and an oil release on November 16.

Also in November 2018, the Spruce Lake East thermal project in Saskatchewan was sanctioned.

In December 2018, the Sunrise Energy Project reached its nameplate capacity of 60,000 bbls/day (30,000 bbls/day Husky working interest).

2019

On January 8, 2019, the Company announced that it would be undertaking a strategic review and potentially selling its Canadian Retail and Commercial Fuels Network and the Prince George Refinery.

On January 16, 2019, the Company's unsolicited offer to acquire all of the outstanding common shares of MEG expired with the minimum tender condition not having been met. The Company did not extend the offer due to a lack of support from the MEG board of directors and MEG shareholders.

On January 30, 2019, partial production resumed at the White Rose field following the shut-in of production announced in November 2018.

On March 15, 2019, the Company issued US$750 million of 4.400% notes maturing on April 15, 2029 by way of a prospectus supplement dated March 13, 2019 to the 2018 U.S. Shelf Prospectus and Registration Statement.

In the first quarter of 2019, regulatory approval was received for the Spruce Lake East thermal project.

On June 12, 2019, the Company entered guilty pleas on federal and provincial charges related to a 2016 oil spill in Saskatchewan and agreed to pay fines totaling $3.82 million.

On August 16, 2019, the Company announced that it would resume full production at the White Rose field.

On August 26, 2019, the Company announced that it had commenced production at its 10,000 barrel-per-day Dee Valley thermal project in Saskatchewan.

On September 30, 2019, the Company announced that it had received the required permit approvals to begin construction activities at the Superior Refinery following the April 2018 fire.

On November 1, 2019, the Company announced the closing of the sale of the Prince George Refinery to Tidewater for $215 million in cash plus a closing adjustment of approximately $53.5 million.

On December 20, 2019, production operations on the *Terra Nova* FPSO were safely shut-in in response to a C-NLOPB order citing insufficient redundancy of fire water pumps. See "Description of Husky's Business - Offshore - Atlantic - Terra Nova Field".

2020

On March 3, 2020, the Company filed the 2020 U.S. Shelf Prospectus and Registration Statement, which enabled the Company to offer up to US$3.0 billion of debt securities, common shares, preferred shares, subscription receipts, warrants and units of the Company in the U.S. On January 26, 2021, the Company terminated the effectiveness of the U.S. registration statement.

On March 12, 2020, the Company announced that it would be cutting its 2020 capital spending by $900 million and $100 million in additional cost-saving measures to fortify its business in response to challenging global market conditions.

On March 22, 2020, the Company announced that it would begin a systematic and orderly suspension of major construction activities related to the West White Rose Project in an effort to prevent the transmission of the COVID-19 virus among the Company's employees and contractors and the local community.

On April 20, 2020, the Company announced that it would cut 2020 capital spending to $1.7 billion, that it had increased its liquidity with the addition of a $500 million term loan, that Integrated Corridor (as defined herein) upstream production had been reduced by over 80,000 bbls/day and that U.S. refinery throughput had been reduced by 95,000 bbls/day.

On April 20, 2020, the Company announced it has suspended the strategic review of its Canadian Retail and Commercial Fuels Network due to the market environment.

On August 4, 2020, the Company announced the release of its 2020 Environment, Social, and Governance Performance Report (the "**ESG Report**"), including a Scope 1 GHG emissions intensity reduction target of 25% by 2025 with an aspiration to be net zero by 2050. The Company also announced a gender diversity target of 25% women in senior leadership roles.

On August 7, 2020, the Company issued $1.25 billion of 3.50% notes maturing on February 7, 2028 by way of a prospectus supplement dated August 5, 2020 to the 2019 Canadian Shelf Prospectus.

On September 2, 2020, the Company announced that it had achieved first oil at the Spruce Lake Central thermal project and that it was moving towards startup of the Liuhua 29-1 field at the Liwan Gas Project.

On September 9, 2020, the Company announced that it would be conducting a review of the scope, schedule and cost of the West White Rose Project as a result of the one-year delay to first oil caused by the COVID-19 pandemic.

On September 29, 2020, the Company announced that commissioning had been completed at the third field at the Liwan Gas Project, ahead of schedule and $100 million below budget.

On October 25, 2020, the Company and Cenovus jointly announced that they had entered into a definitive arrangement agreement under which they would combine in an all-stock transaction by way of plan of arrangement under the ABCA (the "**Cenovus Transaction**").

Recent Developments

On January 4, 2021, the Company announced that the Cenovus Transaction was completed on January 1, 2021. As a result of the Cenovus Transaction, Husky has become a wholly-owned subsidiary of Cenovus, and the Husky common shares and preferred shares were delisted from the TSX at the close of trading on January 5, 2021.

DESCRIPTION OF HUSKY'S BUSINESS

Overview

Husky is a Canadian integrated energy company based in Calgary, Alberta.

Effective January 1, 2020, the Company's businesses were reorganized under two new business segments: (i) an integrated Canada-U.S. upstream and downstream corridor (the "**Integrated Corridor**"); and (ii) production located offshore the east coast of Canada ("**Atlantic**") and offshore China and Indonesia ("**Asia Pacific**" and collectively with Atlantic, "**Offshore**").

Integrated Corridor

The Company's business in the Integrated Corridor includes: (i) the Lloydminster Heavy Oil Value Chain; (ii) Oil Sands; (iii) Western Canada Production; (iv) U.S Refining; and (v) Canadian Refined Products.

The **Lloydminster Heavy Oil Value Chain** includes the exploration for, and development and production of, heavy crude oil and bitumen, and production of ethanol. Blended heavy crude oil and bitumen are either sold directly to the Canadian market or transported utilizing the HMLP pipeline systems to the Keystone pipeline and other pipelines to be sold in the U.S. downstream market. Heavy crude oil can be upgraded at the Upgrader and Asphalt Refinery into synthetic crude oil, diesel fuel and asphalt. This business also includes the marketing and transportation of both the Company's own production and third-party commodity trading volumes of heavy crude oil, synthetic crude oil, asphalt and ancillary products. The sale and transportation of the Company's production and third-party commodity trading volumes are managed through access to capacity on third-party pipelines and storage facilities in both Canada and the U.S. The Company is able to capture price differences between the two markets by utilizing infrastructure capacity to deliver production and/or third-party commodity trading volumes from Canada to the U.S. market.

The **Oil Sands** business includes the exploration for, and development and production of, bitumen within the Sunrise Energy Project. It also includes the marketing and transportation of the Company's and third-party production of bitumen through access to capacity on third-party pipelines and storage facilities in both Canada and the U.S.

The **Western Canada Production** business includes the exploration for, and development and production of, light crude oil, conventional natural gas and NGL in Western Canada. The Company's conventional natural gas and NGL production is marketed and transported with other third-party commodity trading volumes through access to capacity on third-party pipelines, export terminals and storage facilities which provides flexibility for market access.

The **U.S. Refining** business includes the refining of crude oil at the Lima Refinery, the BP-Husky Toledo Refinery and the Superior Refinery in the U.S. Midwest to produce diesel fuel, gasoline, jet fuel, asphalt and other products. The Company also markets its own and third-party volumes of refined petroleum products including gasoline and diesel fuel.

The **Canadian Refined Products** business includes the marketing of its own and third-party volumes of refined petroleum products, including gasoline and diesel, through petroleum outlets.

Offshore

The Company's Offshore business includes operations, development and exploration in Asia Pacific and Atlantic. The price received for Asia Pacific production is largely based on long-term contracts and crude oil production from Atlantic is primarily driven by the price of Brent.

Corporate Strategy

The Company's business strategy is to generate returns from investing in a portfolio of projects and other opportunities across the Integrated Corridor and Offshore businesses. These projects and investments are intended to provide for increasing margins, funds from operations and earnings. A strong balance sheet, deep physical integration and largely fixed price contracts in Asia Pacific provide resilience to market volatility while preserving upside exposure to rising commodity prices.

Integrated Corridor

Third-Party Pipeline Commitments

In 2010, the Company commenced its pipeline commitment on the Keystone pipeline system, which ships Canadian crude oil from Hardisty, Alberta to Patoka, Illinois. This commitment was part of a strategy, commenced in 2006, to expand the market for the Company's crude oil into the U.S. Midwest. This strategy was further supported through the acquisition of the Lima Refinery in 2007, which enabled the Company's Canadian synthetic crude oil and bitumen production, along with additional third-party crude and other feedstocks, to be processed at the refinery. The Company has the ability to utilize the portion of the Keystone pipeline system that continues to Cushing, Oklahoma, and the Company holds long-term firm capacity on the Enbridge Flanagan South pipeline and Southern Access Extension pipeline which connect Enbridge's Mainline to the U.S. Gulf Coast and Patoka markets.

Due to the Company's Keystone pipeline commitment, the Lima Refinery has the ability to access a significant amount of Canadian crude oil as part of its crude feedstock requirements. The Keystone pipeline has enabled the Company to transport crude oil through interconnecting pipeline systems to the Lima Refinery and/or sell it into the Cushing, Oklahoma market.

Since 2012, the pipeline systems leaving Canada have at times been subject to significant apportionment, affecting both Canadian export volumes and crude oil prices in Western Canada. The Company has mitigated these effects through the reliability of its proprietary pipeline system, its priority capacity on export pipelines and its demand for Canadian crude oil feedstock for its Canadian upgrading and refining assets. In 2017, the Company further enhanced this integration when it purchased the 50,000 barrel-per-day Superior Refinery, which runs a combination of heavy Canadian crude and light crudes from Canada and the U.S. The Superior Refinery is located on the Enbridge Mainline crude system. As a seller and buyer of crude oils, the Company has a relatively balanced exposure to many location and grade differentials.

In December of 2018, the Government of Alberta imposed an oil production curtailment order through production quotas. Although the curtailment policy officially runs through 2021, curtailment was reduced to zero effective December 1, 2020.

Commodity Marketing

The Company has developed its commodity marketing operations to include the acquisition of third-party volumes to enhance the value of its Integrated Corridor assets.

Currently, the Company is a marketer of both its own and third-party production of crude oil, synthetic crude oil, NGL, natural gas and sulphur. The Company also markets petroleum coke, a by-product from the Upgrader and its Ohio refineries. The Company supplies feedstock to its Upgrader and Asphalt Refinery from its own and third-party heavy oil and bitumen production sourced from the Lloydminster and Cold Lake areas. The Company also sells blended heavy crude oil directly to refiners based in the U.S. and Canada. The extensive infrastructure in the Lloydminster area supports the Company's heavy crude oil refining, upgrading and marketing operations. The Company markets light and medium crude oil and NGL sourced from its own production and third-party production. Light crude oil is acquired for processing by the Lima Refinery and the Superior Refinery. The Company supplies a portion of the synthetic crude oil produced at its Upgrader to the Lima Refinery and Superior Refinery, and markets the rest to refiners in Canada and the U.S.

The Company markets natural gas sourced from its own production and third-party production. The Company is currently committed to gas sales contracts with third parties, which in aggregate do not exceed amounts forecasted to be deliverable from the Company's reserves. The Company trades natural gas to generate revenue from managed assets, including transportation and natural gas storage facilities.

Lloydminster Heavy Oil Value Chain

Thermal and Non-Thermal Developments

Heavy Oil and Bitumen

The majority of the Company's heavy oil assets are located in the Lloydminster region of Alberta and Saskatchewan, with lands consisting of approximately two million acres. The majority of the Company's operations are 100% working interest. The Company's operations are supported by a network of facilities and pipelines that transport heavy crude oil and bitumen from the field locations to the Asphalt Refinery, the Upgrader and the Company's other assets in the Integrated Corridor, thus providing full integration.

Production of heavy crude oil and bitumen from the Lloydminster area uses a variety of technologies, including SAGD, CHOPS, horizontal wells, waterflooded fields and non-thermal EOR.

Lloydminster Thermal Projects

Lloydminster bitumen production consists of 11 thermal plants located in the Lloydminster region of Saskatchewan: Bolney/Celtic, Dee Valley, Edam East, Edam West, Paradise Hill, Pikes Peak South, Rush Lake 1 & 2, Sandall, Spruce Lake Central and Vawn. Each plant has a number of production pads and utilizes SAGD technology. Lloydminster thermal production has been ramped up to full rates following a deliberate ramp down late in the first quarter of 2020 in response to market conditions. Production in 2020 from Lloydminster thermal projects averaged 81,000 bbls/day.

The Company has an inventory of Saskatchewan thermal projects. These long-life developments are built with modular, repeatable designs and require low sustaining capital once brought online. Late in the first quarter of 2020, market conditions changed materially due to both the COVID-19 pandemic and falling commodity prices. Given the flexible nature of these projects, the Company has reduced activity on all future thermal projects.

The following table shows major projects and their status as at December 31, 2020:

Project Name	Nameplate Capacity (bbls/day)	Expected Project Production Date	Project Status
Spruce Lake Central	10,000	On Production	First oil was achieved on August 26, 2020 with design capacity reached early December.
Spruce Lake North	10,000	2024	Central Processing Facility ("**CPF**") is 81% complete. CPF construction has been placed on hold. Overall project is 69% complete.

The remaining projects were placed on hold due to deteriorating market conditions in 2020 and are undergoing re-evaluation of production options to maximize value.

Tucker Thermal Project

The Tucker Thermal Project is a SAGD oil sands project located 30 kilometres northwest of Cold Lake, Alberta. It commenced bitumen production at the end of 2006.

Bitumen production for 2020 averaged 18,300 bbls/day.

A major plant turnaround was completed for the CPF and field in 2020.

Cold and EOR

Production from the Cold and EOR business consists of a combination of production technologies including CHOPS and horizontal wells and EOR projects.

During 2020, the Company operated three CO_2 injection EOR pilot projects and a CO_2 capture and liquefaction plant at the Lloydminster Ethanol Plant. The liquefied CO_2 is used in the ongoing EOR piloting program. The Company is also piloting a CO_2 capture technology at its Pikes Peak South facility in Saskatchewan.

Production for 2020 averaged 21,400 bbls/day of heavy crude oil, 1,400 bbls/day of medium crude oil and 11.2 mmcf/day of conventional natural gas.

Upgrading Operations

The Company owns and operates the Upgrader. The Upgrader is designed to process blended heavy crude oil feedstock, creating high quality, low sulphur synthetic crude oil and ultra-low sulphur diesel and recovers diluent from the feedstock for return to and reuse in the field. Synthetic crude oil is used as refinery feedstock for the production of transportation fuels in Canada and the U.S.

The Upgrader was commissioned in 1992 with an original design capacity of 46,000 bbls/day of synthetic crude oil. In 2007, the Upgrader commenced production of transportation grade diesel. The Upgrader's current rated production capacity is 81,500 bbls/day of synthetic crude oil, diluent and ultra low sulphur diesel.

Production at the Upgrader averaged 45,872 bbls/day of synthetic crude oil, 11,926 bbls/day of diluent and 6,043 bbls/day of ultra low sulphur diesel in 2020. In addition, as by-products of its upgrading operations, the Upgrader produced approximately 297 long ton/day of sulphur and 774 long ton/day of petroleum coke during 2020. These products are sold in Canadian and international markets.

Lloydminster Asphalt Refinery

The Asphalt Refinery processes heavy crude oil and bitumen into asphalt products used in road construction and maintenance. The refinery has a throughput capacity of 30,000 bbls/day of heavy crude oil and bitumen. The refinery also produces straight run gasoline, bulk distillates and industrial products. The straight run gasoline stream is removed and re-circulated into HMLP's pipeline network as pipeline diluent. The distillate stream is transferred to the Upgrader and treated for blending into the Husky Synthetic Blend ("**HSB**") stream. Industrial products are a blend of medium and light distillate and gas oil streams, which are typically sold directly to customers as refinery feedstock, drilling and well-fracturing fluids, or used in asphalt cutbacks and emulsions.

Refinery throughput averaged 28,000 bbls/day of blended heavy crude oil and bitumen feedstock during 2020. Due to the seasonal demand for asphalt products, many asphalt refineries typically operate at full capacity only during the normal paving season in Canada and the northern U.S. The Company has implemented various strategies to increase refinery throughput during the other months of the year that are outside of the normal paving season, such as increasing storage capacity and developing U.S. markets for asphalt products. This allows the Asphalt Refinery to run at or near full capacity throughout the year.

Asphalt Distribution Network

In addition to sales directly from the Asphalt Refinery, the Company, through its asphalt division, has an asphalt distribution network which consists of seven asphalt terminals located at: Kamloops, British Columbia; Edmonton and Lethbridge, Alberta; Yorkton, Saskatchewan; Winnipeg, Manitoba; Rhinelander, Wisconsin; and Crookston, Minnesota, and an emulsion plant located at Saskatoon, Saskatchewan. The Company also markets asphalt from independently operated terminals in the states of Washington, Minnesota, Wisconsin and Ohio.

The asphalt terminals in Rhinelander, Wisconsin and Crookston, Minnesota and the independently operated terminals in the states of Washington, Minnesota, Wisconsin and Ohio are part of the U.S. Refining business segment.

Ethanol Plants

In September 2006, the Company commissioned an ethanol plant in Lloydminster, Saskatchewan. The plant has an annual nameplate capacity of 130 million litres. In December 2007, the Minnedosa, Manitoba ethanol plant was commissioned also with an annual nameplate capacity of 130 million litres. In 2020, combined ethanol production averaged 733,000 litres/day.

During 2012, the Lloydminster plant commissioned a CO_2 capture facility. The plant is currently capturing CO_2 for use in the Company's non-thermal EOR projects and ethanol produced at the plant has a low carbon intensity designation.

Husky Midstream Limited Partnership

HMLP was created in July 2016 with the sale of selected pipeline gathering systems in Alberta and Saskatchewan and the Lloydminster and Hardisty terminals. CKI Infrastructure Holdings Limited owns 16.25%, Power Assets Holdings Limited owns 48.75% and Husky owns 35% of HMLP and Husky is the operator. HMLP has approximately 2,200 kilometres of pipeline in the Lloydminster region, 5.9 million barrels of storage capacity at Hardisty and Lloydminster and other ancillary assets. The Lloydminster Terminal, with a total storage capacity of 1.0 million barrels, serves as a hub for the gathering systems. The pipeline systems transport blended heavy crude oil to Lloydminster, accessing markets through the Upgrader and Asphalt Refinery. Blended heavy crude oil and bitumen from the field and synthetic crude oil from the upgrading operations are transported south to Hardisty, Alberta to a connection with the major export trunk pipelines. The Hardisty terminal, with a total storage capacity of 4.9 million barrels, acts as the exclusive blending hub for Western Canada Select ("**WCS**"), the largest heavy oil benchmark pricing point in North America. HMLP has diversified its operations with the Ansell Corser Gas Plant, with 120 mmcf/day of processing capacity.

HMLP has a separate board of directors from Husky and independent financing that supports both significant growth projects that are under construction and planned future expansions.

The Hardisty terminal was expanded in 2020 to provide additional pipeline connectivity and crude oil storage for customers. The assets play an integral role in the transportation of heavy oil and bitumen production to end markets by providing connections to the Upgrader and the Asphalt Refinery, third-party terminals and pipelines through strategic hubs such as the Hardisty Terminal.

Oil Sands

Sunrise Energy Project

On March 31, 2008, Husky and BP Corporation North America Inc. completed a transaction that created an integrated North American oil sands and refining businesses. The businesses are comprised of a 50/50 partnership to develop the Sunrise Energy Project, operated by Husky, and a 50/50 limited liability company for the BP-Husky Toledo Refinery, operated by BP Products North America Inc.

The Sunrise Energy Project is a SAGD oil sands project located in the Athabasca region of northern Alberta. Bitumen production in 2020 averaged approximately 44,800 bbls/day (22,400 bbls/day Husky working interest).

At the end of 2020, there were 81 producing wells. Six infills have been drilled and are ready for tie-in. Three additional well pairs will be on production early in 2021.

The scheduled 2020 turnaround on plant 1B was deferred to 2021 due to COVID-19 pandemic concerns.

Western Canada Production

Northern Operations

The Company's Northern Operations are located primarily in northwest Alberta. Production in 2020 consisted of approximately 1,176 bbls/day of light crude oil, 5,208 bbls/day of NGL and 148.2 mmcf/day of conventional natural gas reflecting heavily weighted conventional natural gas production of approximately 79%. Primary areas of operations include Edson and Grande Prairie, where operations are centered on liquids-rich gas resource production.

Edson operations are located primarily in west-central Alberta and consist of the Ansell and Galloway areas. The Ansell natural gas resource play is located in the deep basin Cretaceous formations. The Company holds an average 95% working interest in approximately 177 net sections of contiguous lands. The Company has been actively developing the Spirit River formations since 2012 using multi-stage fractured horizontal wells. Production from the Ansell and Galloway areas has doubled since 2012 and in 2020 averaged 1,420 bbls/day of NGL and 100.1 mmcf/day of conventional natural gas. In 2020, the Company drilled four wells and completed four wells.

Grande Prairie operations are located primarily in northwest Alberta and consist primarily of the Wembley, Kakwa, and Wapiti areas. Production from Grande Prairie in 2020 averaged 1,170 bbls/day of light crude oil, 3,794 bbls/day of NGL and 48.1 mmcf/day of conventional natural gas. A drilling program targeting the oil and liquids-rich natural gas Montney formation in the Wembley area continued with two wells drilled and three wells completed in 2020. Three of these wells were brought on production late in the first quarter of 2020 and had production of 500 boe/day in 2020. The Kakwa Spirit River liquids-rich natural gas resource play averaged 36 bbls/day of light crude oil, 1,861 bbls/day of NGL and 27.8 mmcf/day of conventional natural gas in 2020. Wapiti averaged 976 bbls/day of light crude oil, 585 bbls/day of NGL and 3.8 mmcf/day of conventional natural gas in 2020.

Southern Operations

The Company's Southern Operations are primarily located in central and southern Alberta. As at December 31, 2020, the Company operated three natural gas facilities with approximately 600 active wells throughout the area. Production in 2020 averaged 265 bbls/day of light crude oil, 1,500 bbls/day of NGL and 23.1 mmcf/day of conventional natural gas. In February 2020, the Company sold its assets in the Hussar area. Production from these assets averaged 270 boe/day in 2020.

Rainbow Lake Operations

Rainbow Lake, located approximately 900 kilometres northwest of Edmonton, Alberta, is the site of the Company's largest light crude oil production operation in Western Canada. Production during 2020 from the Rainbow Lake assets averaged 4,286 bbls/day of light crude oil, 3,500 bbls/day of NGL and 78.7 mmcf/day of conventional natural gas.

The Company holds a 50% interest in a 90 megawatt natural gas fired cogeneration facility adjacent to its Rainbow Lake processing plant. The cogeneration facility produces electricity and thermal energy, or steam, for the Rainbow Lake processing plant. Additional electricity is also generated for the Power Pool of Alberta.

Northwest Territories

The Company held two ELs acquired in 2011 in the Northwest Territories at the Slater River Canol shale play, which were consolidated as one EL in 2015 and cover 483,000 gross acres (466,000 net acres). Two pilot wells were drilled and suspended in 2012 which satisfied the requirements to extend the term of both the ELs to their full nine-year term. In 2016, the Company was awarded a Significant Discovery Declaration on 545 sections (150,000 hectares) of land within the ELs north of the Gambill Fault, and granted separately a Significant Discovery Licence over five sections of land south of the Gambill Fault. Abandonment work on the two pilot wells and 12 water monitoring wells in addition to reclamation of well sites and surplus infrastructure were completed in the third quarter of 2019. The existing infrastructure that will remain in place to service the Significant Discovery Declaration is under care and maintenance.

Canadian Refined Products

Retail and Commercial Network

In 2017, the Company and Imperial Oil combined commercial operations to create a single truck transport network of more than 150 cardlock sites, under the Esso brand. As part of the initial agreement, in 2019, 61 locations were converted to offer Esso Synergy fuel, including the retail fuel dispensers at the Company's travel centres, as well as a select number of retail stations across the network.

As of December 31, 2020, there were 546 independently operated Husky and Esso-branded petroleum product outlets. The Company's retail and commercial operating model is balanced by corporate-owned/dealer-operated and branded dealer-owned-and-operated sites. The network consists of a variety of full-and self-serve retail stations, travel centres and cardlocks serving urban and rural markets across the country, while the Company's bulk distributors offer direct sales to commercial and agricultural markets in the Prairie provinces.

On April 20, 2020, the Company announced that it had suspended the strategic review of its Canadian Retail and Commercial Fuels business due to the market environment.

Retail outlets offer a variety of services, including convenience stores, service bays, 24-hour accessibility, car washes, Husky House Restaurants and proprietary and co-branded quick-serve restaurants. In addition to ethanol-blended gasoline, the Company sells diesel, propane and Mobil-branded lubricants to customers. The Company supplies refined petroleum products to its branded independent retailers on an exclusive basis and provides financial and other assistance for location improvements, marketing support and related services.

Other Supply Arrangements

During 2020, the Company purchased approximately 30,399 bbls/day of refined petroleum products of which 27,839 bbls/day were pursuant to agreements with Imperial Oil. The Company also acquired approximately 6,686 bbls/day of refined petroleum products pursuant to exchange agreements with third-party refiners.

The following table shows the number of Husky and Esso-branded petroleum outlets by province as of December 31, 2020:

	British Columbia	Alberta	Saskatchewan	Manitoba	Ontario	Quebec	New Brunswick	**2020 Total**	2019 Total
Husky-Branded Petroleum Outlets									
Retail Owned Outlets	35	41	8	12	54	—	—	150	152
Leased	28	26	3	7	22	—	—	86	91
Independent Retailers	44	56	13	3	13	—	—	129	134
Total	**107**	**123**	**24**	**22**	**89**	**—**	**—**	**365**	377
Esso-Branded Petroleum Outlets									
Retail Owned Outlets	18	19	4	4	15	—	—	60	59
Leased	3	4	—	3	3	—	—	13	13
Independent Retailers	35	24	4	6	32	6	1	108	103
Total	**56**	**47**	**8**	**13**	**50**	**6**	**1**	**181**	175
Cardlocks[(1)]	**51**	**47**	**9**	**11**	**44**	**6**	**1**	**169**	164
Convenience Stores[(1)]	**76**	**79**	**14**	**21**	**92**	**—**	**—**	**282**	291
Restaurants	**8**	**8**	**3**	**1**	**13**	**—**	**—**	**33**	34

(1) Located at branded petroleum outlets.

The Company also markets refined petroleum products directly to various commercial markets, including independent dealers, national rail companies and major industrial and commercial customers in Canada.

The following table shows average daily sales volumes of light refined petroleum products for the periods indicated:

Average Daily Sales Volume *(mbbls/day)*	Years ended December 31,		
	2020	2019	2018
Gasoline	**17.3**	20.5	21.7
Diesel fuel	**24.4**	25.7	26.5
Liquefied petroleum gas	**0.3**	0.5	0.2
	42.0	46.7	48.4

U.S. Refining

Lima Refinery

The Lima Refinery has a crude oil throughput capacity of up to 175,000 bbls/day. The Lima Refinery processes both light sweet crude oil and heavy crude oil feedstock sourced from the U.S. and Canada, which includes Canadian synthetic crude oil, including HSB produced by the Upgrader. The Lima Refinery produces low sulphur gasoline, gasoline blend stocks, ultra-low sulphur diesel, jet fuel, petrochemical feedstock and other by-products. The feedstocks are received via the Mid-Valley and Marathon Pipelines, and the refined products are transported via the Buckeye, Inland and Energy Transfer Partners pipeline systems and by rail car to primary markets in Ohio, Illinois, Indiana, Pennsylvania and southern Michigan.

During 2020, total production throughput at the Lima Refinery averaged 140,000 bbls/day. Production consisted of gasoline averaging 68,000 bbls/day, total distillates averaging 53,000 bbls/day and total other products averaging 19,000 bbls/day.

The crude oil flexibility project was commissioned in early 2020 and is designed to allow for the processing of up to 40,000 bbls/day of heavy crude oil feedstock from Western Canada, providing the ability to swing between light and heavy crude oil feedstock.

BP-Husky Toledo Refinery

The BP-Husky Toledo Refinery has a nameplate capacity of 160,000 bbls/day. Products from the refinery include low sulphur gasoline, ultra-low sulphur diesel, aviation fuels and by-products.

A feedstock optimization project completed during the 2016 turnaround improved the BP-Husky Toledo Refinery's ability to process high-TAN crude oil to support production from the Sunrise Energy Project. Since January 1, 2017, the Company has been marketing its share of the joint operation's refined products.

During 2020, the Company's share of total throughput averaged 65,400 bbls/day, with the Company's share of sales of gasoline averaging 38,900 bbls/day, distillates averaging 20,100 bbls/day and other fuel and feedstock averaging 9,600 bbls/day.

Superior Refinery

On November 8, 2017, the Company completed the acquisition of the Superior Refinery, which had a permitted throughput capacity of 50,000 bbls/day and an operating capacity of 45,000 bbls/day on its crude slate at the time of acquisition. The refinery produces motor fuel products and asphalt from light and heavy crude oil originating from North Dakota and Western Canada.

The refinery also has associated infrastructure including five storage and distribution terminals that are strategically located throughout the northern area of the United States. These terminals include: the Superior products terminal; the Duluth Terminal in Duluth, Minnesota, which has a storage capacity of 200,000 barrels; the Duluth Marine Terminal in Duluth, Minnesota, which has a storage capacity of 14,000 barrels; the Rhinelander Terminal in Rhinelander, Wisconsin, which has a storage capacity of 166,000 barrels; and the Crookston Terminal in Crookston, Minnesota, which has a storage capacity of 156,000 barrels.

On April 26, 2018, the Superior Refinery experienced an incident while preparing for a major turnaround and was taken out of operation. During 2019, demolition, site preparation work and permitting were completed, and the rebuild work commenced. The rebuild is ongoing and the Company anticipates a substantial portion of the investment will be recovered from property damage insurance. The refinery is expected to restart around the first quarter of 2023, with a nameplate processing capacity of 49,000 mbbls/day, including capability to process up to 34,000 bbls/day of heavy oil while producing asphalt, gasoline and diesel.

Offshore

Asia Pacific

China

Liwan Gas Project

The Liwan Gas Project includes the natural gas discoveries at the Liwan 3-1, Liuhua 34-2 and Liuhua 29-1 fields within the Contract Area 29/26 exploration block located in the Pearl River Mouth Basin of the South China Sea, approximately 300 kilometres southeast of the Hong Kong Special Administrative Region.

The Company has a 49% working interest in the Liwan 3-1 and Liuhua 34-2 fields and a 75% working interest in the Liuhua 29-1 field, and CNOOC has 51% and 25% working interests, respectively. The initial development of the Liwan 3-1 and Liuhua 34-2 fields was separated into deepwater and shallow water development projects, with the Company acting as operator of the deepwater wells, the deepwater production systems and the pipeline while CNOOC is the operator of the shallow water platform and the onshore gas processing facility at Gaolan. The deepwater infrastructure includes the production wells and trees, as well as the subsea pipelines and infrastructure that produces through twin 22-inch deepwater pipelines running approximately 78 kilometres to the "shallow water" central platform which is about 260 km from shore. The shallow water infrastructure includes the central platform ("**CEP**") standing in approximately 200 metres of water, a 261-kilometre 30-inch shallow water pipeline running from the CEP to the Gaolan Onshore Gas Plant ("**OSGP**"), which has liquids separation facilities, NGL storage tanks, a gas liquids export jetty, a facility control system as well as administrative and accommodation buildings.

The Liwan 3-1 field commenced production at the end of March 2014. The gas field is currently producing from nine wells. The single production well in the Liuhua 34-2 field was tied into the deepwater facilities of the Liwan 3-1 field and commenced production in December 2014.

An amendment to the gas sales agreement for the Liwan 3-1 field was executed in the third quarter of 2020. The amendment is effective from August 1, 2020 until April 30, 2022, and has the effect of increasing the volume of gas the buyer must take or pay during the term, and lowering the effective price of this gas. Following April 30, 2022, the original gas sales agreement terms will take effect. Husky anticipates no material impact to its cash flow from the Liwan 3-1 field as a result.

Construction work was completed in the third quarter of 2020 at Liuhua 29-1, the third deepwater gas field of the Liwan Gas Project. First gas production from the Liuhua 29-1 development started in November 2020 and sales were initiated that same month. This seven-well subsea development is fully installed and utilizes the existing Liwan Gas Gathering system and the facilities located on the CEP and Gaolan OSGP. The buyer began taking 40 mmcf/d on November 4, 2020.

In 2020, total gas sales from Liwan 3-1, Liuhua 34-2 and Liuhua 29-1 averaged 366 mmcf/day, 34 mmcf/day and 6 mmcf/day, respectively. In 2020, the Company's working interest share of production from the three fields was 201 mmcf/day of conventional natural gas and 8,600 bbls/day of NGL.

Block 15/33

The Company executed a PSC in December 2015 for an exploration block offshore China. Block 15/33 is located in the Pearl River Mouth Basin in the South China Sea, about 140 kilometres southeast of the Hong Kong Special Administrative Region and covers an area of 155 square kilometres in water depths of approximately 80 to 100 metres. The Company is the operator of the block during the exploration phase, with a working interest of 100%. In the event of a commercial discovery, its partner CNOOC may assume a working interest of up to 51% during the development and production phase by paying its proportional share of all development costs. Under the PSC, the corresponding CNOOC share of exploration costs is to be recovered from production allocated to the Company.

In the third quarter of 2020, an agreement was signed between the Company and CNOOC to extend the end of the second phase of exploration period of the PSC to December 31, 2021.

Block 16/25

The Company executed a PSC in April 2017 for an exploration block offshore China. Block 16/25 is located in the Pearl River Mouth Basin in the South China Sea, about 150 kilometres southeast of the Hong Kong Special Administrative Region and approximately 72 kilometres northeast of Block 15/33. The block covers an area of 44 square kilometres in water depths of approximately 85 to 100 metres.

The Company drilled one exploration well in the third quarter of 2018, which encountered non-commercial hydrocarbons. This well was written off in 2019.

During 2020, an amendment agreement was signed between the Company and CNOOC under which the first phase of the exploration period was extended to April 30, 2022, with the remaining obligatory exploration well to be completed in an area to be agreed upon by the parties. The initial contract area under the Block 16/25 petroleum contract was relinquished pursuant to the terms of the amendment agreement.

Blocks 22/11 and 23/07

The Company and CNOOC signed two PSCs for Blocks 22/11 and 23/07 in the Beibu Gulf area of the South China Sea in the first half of 2018. The Company is the operator of both blocks with a working interest of 100% during the exploration phase. In the event of a commercial discovery, its partner CNOOC may assume a participating partnership interest of up to 51% in either or both blocks for the development and production phases. The Company entered into the two-year exploration phase II of the PSC for Block 23/07 and committed to drill one exploration well before November 30, 2021. Block 22/11 was relinquished during 2020.

Taiwan

In December 2012, the Company signed a joint venture agreement with CPC Corporation, the Taiwan national oil and gas company. The Company and CPC Corporation have rights to an exploration block in the South China Sea covering approximately 7,700 square kilometres located southwest of the island of Taiwan. The Company holds a 75% working interest during exploration, while CPC Corporation holds the remaining 25% and has the right to participate in any development programs up to a 50% interest.

The acquisition of 2-D seismic survey data was completed in 2014, and the acquisition of 3-D seismic survey data was completed in 2017.

Indonesia

Madura Strait

The Company has a 40% interest in the joint venture that holds the Madura Strait PSC encompassing approximately 622,000 acres (2,516 square kilometres) in the Madura Strait area, located offshore East Java, Indonesia. The Company's two partners in the incorporated joint venture are CNOOC, which is the contracted operator and has a 40% working interest, and Samudra Energy Ltd., which holds the remaining 20 percent interest through its affiliate, SMS Development Ltd. The Madura Strait includes the operating BD field and future developments at the MDA, MBH, MDK and MAC fields.

In 2020, total BD field sales averaged 86 mmcf/day of gas and 6,000 bbls/day of associated liquids. The Company's working interest share of production was 34 mmcf/day of conventional natural gas and 2,400 bbls/day of NGL.

At the MDA and MBH fields, the two shallow water platforms have been fully installed. Five MDA and two MBH field production wells are scheduled to be drilled in the 2021/22 timeframe. The Indonesian energy regulator has approved amendments to the Floating Production Unit ("**FPU**") construction contract to facilitate financing. The contracting consortium has ordered long lead equipment and is completing shipyard selection while finalizing financing to fund FPU construction. Pending completion of financing and construction of the vessel, gas sales are expected to begin in 2022. An additional shallow water field, MDK, is scheduled to be developed and tied into the MDA and MBH infrastructure. The processed gas from these three fields will be tied directly into the East Java subsea pipeline system and sold to the East Java market under long-term contracts.

At the stand-alone MAC field development, tendering for engineering, procurement and construction of all required facilities was completed early in the first quarter of 2020. Tendering for the Mobile Offshore Production Unit is in progress and a final investment decision is expected in 2021.

In Indonesia, the energy regulator has made provisions for certain industrial gas buyers to have their gas purchase price reduced. The result is that the gas sales price for a portion of BD field gas production has been reduced, however, the government has compensated the PSC contractor for reduced revenues by way of lower royalty payments. As a result, Husky anticipates no material impact to its cash flow from the BD field.

Anugerah

The Company executed a PSC in February 2014 with the Government of Indonesia for the Anugerah contract area. The Company held a 100% interest in the Anugerah Block, which is located in the East Java Basin approximately 150 kilometres east of the Madura Strait. The block covered an area of 2,030,000 acres (8,215 square kilometres).

During 2015, the Company previously acquired 2-D seismic and 3-D seismic survey data on the contract area, which was required during the first three years of the PSC. An analysis of those data and data from offset block information indicated that exploratory drilling is not economic. The block was relinquished in 2020.

Atlantic

Overview

The Company's Atlantic exploration and development program has been focused in the Jeanne d'Arc Basin and the Flemish Pass offshore NL. The Jeanne d'Arc Basin contains the Hibernia, Terra Nova and Hebron fields, as well as the White Rose field and satellite extensions, including North Amethyst, West White Rose and South White Rose. In the Flemish Pass Basin, the Company holds a 35% non-operated working interest in each of the Bay du Nord, Bay de Verde, Baccalieu, Harpoon and Mizzen discoveries. The Company is the operator of the White Rose field and satellite extensions and holds an ownership interest in the Terra Nova field, as well as a number of smaller undeveloped fields. The Company also holds significant exploration acreage offshore NL.

White Rose Field and Satellite Extensions

The White Rose field is located 354 kilometres off the coast of NL and is approximately 48 kilometres east of the Hibernia field on the eastern flank of the Jeanne d'Arc Basin. The Company is the operator of the main White Rose field and satellite tiebacks, including the North Amethyst, West White Rose and South White Rose extensions. The Company has a 72.5% working interest in the main field and a 68.875% working interest in the satellite extensions. To date, production has been facilitated via subsea tie-ins with wells drilled independently through drill centres and connected via flowlines to the *SeaRose* FPSO.

First oil was achieved at White Rose in November 2005. The White Rose field currently has 13 production wells, 10 water injection wells and three gas injection wells. The Company's share of light crude oil production from the White Rose field was 8,400 bbls/day (Husky working interest) during 2020.

On May 31, 2010, first oil was achieved from North Amethyst, the first satellite extension at the White Rose field. The field is located approximately six kilometres southwest of the *SeaRose* FPSO. Production flows from North Amethyst to the *SeaRose* FPSO through a series of subsea flow lines. As of December 31, 2020, the field had seven production wells, four water injection wells and one gas injection well. During 2020, a production well was converted to gas injection service as an improved oil recovery initiative. Light crude oil production from North Amethyst was 4,200 bbls/day (Husky working interest) in 2020.

Initial production from West White Rose was achieved in September 2011 through a two-well pilot project. The pilot wells have helped provide further information on the reservoir to refine development plans for the full West White Rose field. During 2020, light crude oil production from this satellite field was 300 bbls/day (Husky working interest).

Production commenced from the South White Rose Extension in 2015 with production wells supported by both gas flood and water injection. As at December 31, 2020, the project had three production wells, one water injection well and one gas injection well. During 2020, light crude oil production from the South White Rose Extension was 4,700 bbls/day (Husky working interest).

In May 2017, the Company and its co-venturers announced plans to proceed with full field development at West White Rose using a fixed drilling platform. Construction of various components for the West White Rose platform is underway at sites in NL, and in Ingleside, Texas, where the facility's topsides are being fabricated. Major construction was suspended in March 2020 due to the COVID-19 situation. In October, the Company announced the continued suspension of construction on the Concrete Gravity Structure in Argentia, NL.

As of December 31, 2020, the West White Rose Project was approximately 60% complete.

Terra Nova Field

The Terra Nova field is located approximately 350 kilometres southeast of St. John's, NL. The Terra Nova field is divided into three distinct areas, known as the Graben, the East Flank and the Far East. Production at Terra Nova commenced in January 2002. The Company's working interest in the field increased to 13% effective December 1, 2010.

As at December 31, 2020, there were 15 development wells drilled in the Graben area, consisting of nine production wells, four water injection wells and two gas injection wells. In the East Flank area, there were 12 development wells, consisting of eight production wells and four water injection wells. The Far East has one extended reach producer and an extended reach water injection well.

Production at Terra Nova has been shut in since December 2019. There was no production from the field during 2020.

East Coast Exploration

The Company holds working interests ranging from 5.8% to 100% in 24 significant discovery areas in the Jeanne d'Arc Basin and Flemish Pass Basin, offshore NL and Baffin Island.

The Company continues to evaluate previous hydrocarbon discoveries at the White Rose A-24 exploration well, north of the *SeaRose* FPSO (2018), and the Northwest White Rose A-78 well (2017).

The Company and its partner continue to assess potential development of Bay du Nord and other discoveries in the Flemish Pass Basin. The Company holds a 35% non-operated working interest in the Bay du Nord, Bay de Verde, Baccalieu, Harpoon and Mizzen discoveries. A Significant Discovery Licence was issued for the Harpoon discovery in October 2020.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Disclosure of Oil and Gas Activities

Operating Netback Analysis[1]

The following tables show the Company's netback analysis by product and area:

	Year Ended	Three Months Ended			
Average Per Unit Amounts	**Dec 31, 2020**	**Dec 31, 2020**	Sept 30, 2020	June 30, 2020	Mar 31, 2020
Company Total[2]					
Production volume *(mboe/day)*	**272.0**	**284.2**	258.4	246.5	298.9
Gross Revenue *($/boe)*[3]	**$33.43**	**$39.11**	$38.53	$27.28	$28.59
Royalties *($/boe)*	**$2.10**	**$2.53**	$2.40	$1.45	$1.95
Production and Operating Costs *($/boe)*[3]	**$13.57**	**$12.88**	$13.93	$13.12	$14.29
Transportation Costs *($/boe)*[4]	**$0.18**	**$0.19**	$0.17	$0.20	$0.16
Operating netback *($/boe)*	**$17.58**	**$23.51**	$22.03	$12.51	$12.19
Light and Medium Crude Oil *($/bbl)*					
Canada - Western Canada					
Gross Revenue[3]	**$37.93**	**$43.67**	$43.81	$20.91	$42.95
Royalties	**$3.71**	**$4.02**	$2.68	$1.48	$5.96
Production and Operating Costs[3]	**$27.28**	**$31.86**	$27.45	$24.27	$26.50
Operating netback	**$6.94**	**$7.79**	$13.68	($4.84)	$10.49
Canada - Atlantic Canada					
Gross Revenue	**$49.31**	**$64.70**	$55.74	$34.22	$45.45
Royalties	**$2.76**	**$3.79**	$3.36	$1.99	$2.15
Production and Operating Costs	**$27.77**	**$24.62**	$34.74	$26.62	$26.37
Transportation Costs[4]	**$2.74**	**$3.11**	$3.03	$2.53	$2.39
Operating netback	**$16.04**	**$33.18**	$14.61	$3.08	$14.54
Canada - Total					
Gross Revenue[3]	**$46.03**	**$59.34**	$52.08	$30.64	$44.66
Royalties	**$3.04**	**$3.85**	$3.15	$1.85	$3.37
Production and Operating Costs[3]	**$27.63**	**$26.47**	$32.51	$25.99	$26.41
Transportation Costs[4]	**$1.95**	**$2.31**	$2.09	$1.85	$1.63
Operating netback	**$13.41**	**$26.71**	$14.33	$0.95	$13.25
Heavy Crude Oil *($/bbl)*					
Canada - Total					
Gross Revenue[3]	**$27.09**	**$36.82**	$36.51	$13.82	$22.11
Royalties	**$2.29**	**$2.65**	$2.77	$2.07	$1.87
Production and Operating Costs[3]	**$27.78**	**$27.60**	$26.98	$27.17	$28.73
Operating netback	**($2.98)**	**$6.57**	$6.76	($15.42)	($8.49)
Bitumen *($/bbl)*					
Canada - Total					
Gross Revenue[3][4]	**$24.56**	**$32.57**	$33.99	$13.06	$16.38
Royalties	**$1.69**	**$2.03**	$2.96	$0.50	$1.09
Production and Operating Costs[3]	**$12.78**	**$12.03**	$13.45	$13.86	$12.21
Operating netback	**$10.09**	**$18.51**	$17.58	($1.30)	$3.08

Average Per Unit Amounts	Year Ended Dec 31, 2020	Three Months Ended Dec 31, 2020	Sept 30, 2020	June 30, 2020	Mar 31, 2020
Conventional Natural Gas *($/mcf)*					
Canada - Total					
Gross Revenue[(3)(5)]	**$2.06**	**$2.41**	$2.09	$1.85	$1.94
Royalties[(5)(6)]	**($0.02)**	**$0.09**	($0.30)	$0.01	$0.10
Production and Operating Costs[(3)]	**$1.80**	**$1.86**	$1.66	$1.69	$1.98
Operating netback	**$0.28**	**$0.46**	$0.73	$0.15	($0.14)
China					
Gross Revenue	**$13.94**	**$12.58**	$13.52	$15.00	$14.93
Royalties	**$0.81**	**$0.86**	$0.81	$0.79	$0.79
Production and Operating Costs	**$0.84**	**$0.85**	$1.06	$0.56	$0.94
Operating netback	**$12.29**	**$10.87**	$11.65	$13.65	$13.20
Indonesia[(7)]					
Gross Revenue	**$9.72**	**$9.25**	$9.19	$10.36	$10.05
Royalties	**$0.72**	**$0.59**	$0.27	$0.91	$1.10
Production and Operating Costs	**$1.47**	**$1.59**	$1.33	$1.58	$1.38
Operating netback	**$7.53**	**$7.07**	$7.59	$7.87	$7.57
Total					
Gross Revenue[(3)]	**$7.40**	**$7.53**	$7.16	$7.74	$7.16
Royalties	**$0.37**	**$0.48**	$0.19	$0.39	$0.42
Production and Operating Costs[(3)]	**$1.39**	**$1.38**	$1.39	$1.23	$1.56
Operating netback	**$5.64**	**$5.67**	$5.58	$6.12	$5.18
Natural Gas Liquids *($/bbl)*					
Canada - Total					
Gross Revenue[(3)]	**$14.60**	**$18.32**	$15.24	$6.62	$18.53
Royalties	**$1.06**	**$1.63**	$1.03	($0.16)	$1.77
Production and Operating Costs[(3)]	**$10.03**	**$10.38**	$9.21	$9.50	$11.01
Operating netback	**$3.51**	**$6.31**	$5.00	($2.72)	$5.75
China					
Gross Revenue	**$48.36**	**$52.56**	$48.33	$34.72	$60.62
Royalties	**$2.78**	**$3.08**	$2.76	$1.98	$3.45
Production and Operating Costs	**$5.05**	**$5.08**	$6.34	$3.38	$5.64
Operating netback	**$40.53**	**$44.40**	$39.23	$29.36	$51.53
Indonesia[(7)]					
Gross Revenue	**$57.20**	**$52.48**	$64.61	$13.09	$83.68
Royalties	**$9.21**	**$7.58**	$9.64	$5.47	$12.78
Production and Operating Costs	**$8.63**	**$9.52**	$7.78	$9.46	$8.27
Operating netback	**$39.36**	**$35.38**	$47.19	($1.84)	$62.63
Total					
Gross Revenue[(3)]	**$33.16**	**$37.75**	$35.21	$19.21	$40.95
Royalties	**$2.69**	**$2.91**	$2.93	$1.23	$3.73
Production and Operating Costs[(3)]	**$7.84**	**$7.83**	$7.88	$6.87	$8.86
Operating netback	**$22.63**	**$27.01**	$24.40	$11.11	$28.36

(1) Operating netback is a non-GAAP measure. Refer to the Reader Advisories for further details.
(2) Includes associated co-products converted to boe and mcf.
(3) Transportation expenses have been deducted from both gross revenue and production and operating costs to reflect the actual price received at the oil and gas lease.
(4) Includes offshore transportation costs shown separately from price received.
(5) Includes sulphur sales revenues/royalties.
(6) Alberta Gas Cost Allowance reported exclusively as gas royalties.
(7) Revenues and expenses related to the Husky-CNOOC Madura Ltd. joint venture are accounted for under the equity method for consolidated financial statement purposes.

Production History

Average Gross Daily Production	Year Ended Dec 31, 2020	Three Months Ended Dec 31, 2020	Sept 30, 2020	June 30, 2020	Mar 31, 2020
Canada - Western Canada					
Light and Medium Crude Oil *(mbbls/day)*	**7.2**	5.8	6.5	7.0	9.2
Heavy Crude Oil *(mbbls/day)*	**21.4**	20.2	18.4	16.7	30.4
Bitumen *(mbbls/day)*	**121.8**	136.4	117.4	95.1	138.0
Conventional Natural Gas *(mmcf/day)*	**261.2**	237.3	253.2	275.8	278.9
NGL *(mbbls/day)*	**10.2**	9.3	10.0	10.6	10.9
Canada - Atlantic					
Light and Medium Crude Oil *(mbbls/day)*	**17.6**	17.1	14.8	19.0	19.6
China - Asia Pacific[(1)]					
Conventional Natural Gas *(mmcf/day)*	**201.3**	229.2	190.7	211.3	174.0
NGL *(mbbls/day)*	**8.6**	10.1	8.4	9.3	6.8
Indonesia - Asia Pacific[(2)]					
Conventional Natural Gas *(mmcf/day)*	**34.4**	32.3	34.9	34.6	35.7
NGL *(mbbls/day)*	**2.4**	2.2	3.1	1.8	2.6
Total Gross Production *(mboe/day)*	**272.0**	284.2	258.4	246.5	298.9

(1) Reported production volumes include Husky's working interest production from the Liwan Gas Project.
(2) Reported production volumes include Husky's working interest production from the BD Project (40%). Revenues and expenses related to the Husky-CNOOC Madura Ltd. joint venture are accounted for under the equity method for consolidated financial statement purposes.

Producing and Non-Producing Wells[(1)(2)(3)]

Producing Wells	Oil Wells Gross	Oil Wells Net	Conventional Natural Gas Wells Gross	Conventional Natural Gas Wells Net	Total Gross	Total Net
Canada						
Alberta	1,218	1,071	1,168	788	2,386	1,859
Saskatchewan	2,009	1,954	77	76	2,086	2,030
British Columbia	—	—	120	120	120	120
Newfoundland	22	6	—	—	22	6
	3,249	3,031	1,365	984	4,614	4,015
International						
China	—	—	17	10	17	10
Indonesia	—	—	4	2	4	2
	—	—	21	12	21	12
As at December 31, 2020	**3,249**	**3,031**	**1,386**	**996**	**4,635**	**4,027**

Non-Producing Wells	Oil Wells Gross	Oil Wells Net	Conventional Natural Gas Wells Gross	Conventional Natural Gas Wells Net	Total Gross	Total Net
Canada						
Alberta	1,451	1,336	721	560	2,172	1,896
Saskatchewan	3,560	3,420	172	155	3,732	3,575
British Columbia	—	—	12	10	12	10
As at December 31, 2020	**5,011**	**4,756**	**905**	**725**	**5,916**	**5,481**

(1) The number of gross wells is the total number of wells in which the Company owns a working interest. The number of net wells is the sum of the fractional interests owned in the gross wells. Productive wells are those producing or capable of producing at December 31, 2020.
(2) The above table does not include producing wells in which the Company has no working interest but does have a royalty interest. At December 31, 2020, the Company had a royalty interest in 794 wells, of which 417 were oil producers and 377 were gas producers.
(3) For purposes of the table, multiple completions are counted as a single well. Where one of the completions in a given well is an oil completion, the well is classified as an oil well. In 2020, there were 940 gross and 855 net oil wells and 69 gross and 57 net conventional natural gas wells that were completed in two or more formations and from which production is not commingled.

Of the 21 mmboe of Proved Developed Non-Producing reserves as of year-end 2020, approximately 15 mmboe are associated with wells drilled in the thermal bitumen projects and Sunrise Energy Project that will be placed on production in 2021 and 2022, respectively. An additional 2 mmboe are associated with the Company's Wembley liquids-rich gas resource play. The remaining 4 mmboe are associated with temporarily shut-in wells and optimization programs within existing fields scheduled over the next five years. Because the remaining capital is small relative to drilling and completion costs, the associated reserves are considered developed. There are no other non-producing wells attributed with material reserves.

Properties with No Attributed Reserves

Unproved Acreage *(thousands of acres)*	Gross	Net
Western Canada		
Alberta	2,699	2,302
Saskatchewan	569	552
British Columbia	139	125
	3,407	2,979
Northwest Territories and Arctic	451	443
Atlantic	2,654	1,010
	6,512	4,432
China	292	280
Indonesia	618	247
Taiwan	1,904	1,428
As at December 31, 2020	**9,326**	**6,387**

Where Husky holds interests in different formations under the same surface area pursuant to separate leases, the acreage for each lease is included in the gross and net amounts.

As at December 31, 2020, over the next 12 months, development rights to approximately 241 thousand net acres, or less than 8%, of the Company’s net unproved acreage in Western Canada will be subject to expiry.

As at December 31, 2020, over the next 12 months, development rights to the 1,428 thousand net acres in Taiwan are subject to expiry.

The Company has commitments totaling approximately $103 million related to exploration to be completed in Atlantic between 2023 and 2024. Not fulfilling commitments in accordance with licensing timelines triggers forfeiture of security deposits of 30% of unfulfilled commitments.

The Company has a work deficiency penalty payment of approximately $45 million to secure the Significant Discovery Licence in the Northwest Territories.

The Company has commitments for offshore China of approximately $13 million to be completed by April 30, 2022.

Significant Factors or Uncertainties Relevant to Properties with No Attributed Reserves

The Company holds interests in a diverse portfolio of undeveloped petroleum assets in Western Canada, Atlantic, Asia Pacific, the Northwest Territories and the Arctic. As part of its active portfolio management, the Company continually reviews the economic viability of its undeveloped properties using industry-standard economic evaluation techniques and pricing and economic environment assumptions. Each year, as part of this active management process, some properties are selected for further development activities, while others are held in abeyance, sold, swapped or relinquished back to the mineral rights owner. There is no guarantee that commercial reserves will be discovered or developed on these properties.

Abandonment and Reclamation Costs

There are no significant abandonment or reclamation costs, no unusually high expected development costs or operating costs and no contractual obligations to produce and sell a significant portion of production at prices substantially below those which could be realized but for those contractual obligations that have affected, or that the Company reasonably expects to affect, anticipated development or production activities on properties with no attributed reserves. For further information on abandonment and reclamation costs in respect of the Company's properties, please refer to Note 18 of the Company's audited consolidated financial statements as at and for the year ended December 31, 2020.

Drilling Activity - Number of Wells Drilled

	Year Ended December 31, 2020							
	Western Canada		Atlantic		China		Indonesia	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Exploration								
Oil	—	—	—	—	—	—	—	—
Gas	—	—	—	—	—	—	—	—
	—	—	—	—	—	—	—	—
Development								
Oil	74.0	70.0	—	—	—	—	—	—
Gas	6.0	6.0	—	—	—	—	—	—
	80.0	76.0	—	—	—	—	—	—
	80.0	**76.0**	**—**	**—**	**—**	**—**	**—**	**—**
Stratigraphic Test Wells	**1.0**	**1.0**	**—**	**—**	**—**	**—**	**—**	**—**
Service Wells	**22.0**	**22.0**	**—**	**—**	**—**	**—**	**—**	**—**

Costs Incurred

($millions)	Total	Western Canada	Atlantic	Total Canada	China	Indonesia[(1)]
Property acquisition - Unproven	1	1	—	1	—	—
Property acquisition - Proven	—	—	—	—	—	—
Exploration	7	—	4	4	3	—
Development	1,094	670	260	930	161	3
2020	**1,102**	**671**	**264**	**935**	**164**	**3**

(1) Capital expenditures related to the Husky-CNOOC Madura Ltd. joint venture are accounted for under the equity method for consolidated financial statement purposes.

Oil and Gas Reserves Disclosure

Overview

Husky's oil and gas reserves are estimated in accordance with the standards contained in the Canadian Oil and Gas Evaluation Handbook ("**COGEH**"), and the reserves data disclosed conforms with the requirements of National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities ("**NI 51-101**"). All of Husky's oil and gas reserves estimates are prepared by internal qualified reserves evaluation staff using a formalized process for determining, approving and booking reserves.

For the purposes of Husky's NI 51-101 reserves disclosure in this year's AIF, Sproule Associates Limited. ("**Sproule**"), an independent firm of qualified reserves evaluators, was engaged to conduct a complete audit and review of 100% of Husky's oil and gas reserves estimates. Sproule issued an audit opinion stating that Husky's internally generated proved and probable reserves and net present values based on forecast and constant price assumptions are, in aggregate, reasonable, and have been prepared in accordance with generally accepted oil and gas engineering and evaluation practices as set out in the COGEH.

The Audit Committee has examined Husky's procedures for assembling and reporting reserves data and other information associated with oil and gas activities and has reviewed that information with management. The Board has approved, on the recommendation of the Audit Committee , the content of Husky's disclosure in this AIF of its reserves data and other oil and gas information.

Disclosure of Oil and Gas Information

Unless otherwise noted in this document, all provided reserves estimates have a preparation date of January 25, 2021 and an effective date of December 31, 2020 and are Husky's total proved and probable reserves. Gross reserves or gross production are reserves or production attributable to Husky's working interest prior to deduction of royalties; net reserves or net production represent the Company's lessor royalty, overriding royalty and working interest share of the gross remaining reserves, after deduction of any crown, freehold and overriding royalty interests. Gross or net production reported refers to sales volume, unless otherwise indicated. Unless otherwise noted, production and reserves figures are stated on a gross basis. Unless otherwise indicated, oil and gas commodity prices are quoted after the effects of hedging gains and losses. Unless otherwise indicated, all financial information is in accordance with IFRS. Note that the numbers in each column of the tables throughout this section may not add due to rounding.

The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

Bitumen reserves include reserves from Husky's thermal projects in the Lloydminster area.

The reserves information prepared in accordance with the rules of the U.S. Financial Accounting Standards Board and the SEC (collectively, the "**U.S. Rules**") is included in the Company's Form 40-F, which is available at www.sec.gov and on the Company's website at www.huskyenergy.com. The material difference between reserves quantities disclosed under NI 51-101 and those disclosed under the U.S. Rules is that NI 51-101 requires the determination of reserves quantities to be based on forecast pricing assumptions whereas the U.S. Rules require the determination of reserves quantities to be based on constant price assumptions calculated using a 12-month average price for the year (sum of the benchmark price on the first calendar day of each month in the year divided by 12).

Summary of Oil and Conventional Natural Gas Reserves
As at December 31, 2020
Forecast Prices and Costs

Canada

	Light & Medium Crude Oil *(mmbbls)*		Heavy Crude Oil *(mmbbls)*		Bitumen *(mmbbls)*		Total Oil *(mmbbls)*	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Proved								
Developed Producing	20.4	18.1	31.0	30.0	123.8	115.8	175.1	163.9
Developed Non-producing	1.0	0.9	0.7	0.7	14.6	14.1	16.3	15.7
Undeveloped	—	—	1.1	1.1	759.2	703.8	760.3	704.9
Total Proved	21.4	19.0	32.8	31.8	897.5	833.7	951.7	884.5
Probable	147.0	134.9	16.1	15.6	255.1	228.5	418.2	379.0
Total Proved Plus Probable	**168.3**	**153.9**	**48.9**	**47.4**	**1,152.6**	**1,062.2**	**1,369.9**	**1,263.5**

	Conventional Natural Gas *(bcf)*		Natural Gas Liquids *(mmbbls)*		Total *(mmboe)*	
	Gross	Net	Gross	Net	Gross	Net
Proved						
Developed Producing	562.2	496.9	25.7	20.8	294.5	267.5
Developed Non-producing	19.6	17.7	1.5	1.3	21.1	19.9
Undeveloped	119.0	112.7	8.3	7.5	788.4	731.3
Total Proved	700.8	627.4	35.5	29.6	1,104.0	1,018.7
Probable	301.6	281.7	20.5	17.9	489.0	443.9
Total Proved Plus Probable	**1,002.3**	**909.0**	**56.0**	**47.5**	**1,592.9**	**1,462.5**

China

	Light & Medium Crude Oil *(mmbbls)*		Heavy Crude Oil *(mmbbls)*		Bitumen *(mmbbls)*		Total Oil *(mmbbls)*	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Proved								
Developed Producing	—	—	—	—	—	—	—	—
Developed Non-producing	—	—	—	—	—	—	—	—
Undeveloped	—	—	—	—	—	—	—	—
Total Proved	—	—	—	—	—	—	—	—
Probable	—	—	—	—	—	—	—	—
Total Proved Plus Probable	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**

	Conventional Natural Gas *(bcf)*		Natural Gas Liquids *(mmbbls)*		Total *(mmboe)*	
	Gross	Net	Gross	Net	Gross	Net
Proved						
Developed Producing	493.3	472.4	17.6	16.9	99.8	95.6
Developed Non-producing	—	—	—	—	—	—
Undeveloped	—	—	—	—	—	—
Total Proved	493.3	472.4	17.6	16.9	99.8	95.6
Probable	62.5	59.2	1.9	1.8	12.3	11.7
Total Proved Plus Probable	**555.9**	**531.6**	**19.5**	**18.7**	**112.1**	**107.3**

Indonesia

	Light & Medium Crude Oil *(mmbbls)*		Heavy Crude Oil *(mmbbls)*		Bitumen *(mmbbls)*		Total Oil *(mmbbls)*	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Proved								
Developed Producing	—	—	—	—	—	—	—	—
Developed Non-producing	—	—	—	—	—	—	—	—
Undeveloped	—	—	—	—	—	—	—	—
Total Proved	—	—	—	—	—	—	—	—
Probable	—	—	—	—	—	—	—	—
Total Proved Plus Probable	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**

	Conventional Natural Gas *(bcf)*		Natural Gas Liquids *(mmbbls)*		Total *(mmboe)*	
	Gross	Net	Gross	Net	Gross	Net
Proved						
Developed Producing	128.5	89.8	4.3	2.9	25.7	17.9
Developed Non-producing	—	—	—	—	—	—
Undeveloped	68.4	44.6	—	—	11.4	7.4
Total Proved	197.0	134.5	4.3	2.9	37.1	25.3
Probable	56.6	30.6	1.7	1.0	11.1	6.1
Total Proved Plus Probable	**253.5**	**165.1**	**5.9**	**3.9**	**48.2**	**31.4**

Total

	Light & Medium Crude Oil *(mmbbls)*		Heavy Crude Oil *(mmbbls)*		Bitumen *(mmbbls)*		Total Oil *(mmbbls)*	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Proved								
Developed Producing	20.4	18.1	31.0	30.0	123.8	115.8	175.1	163.9
Developed Non-producing	1.0	0.9	0.7	0.7	14.6	14.1	16.3	15.7
Undeveloped	—	—	1.1	1.1	759.2	703.8	760.3	704.9
Total Proved	21.4	19.0	32.8	31.8	897.5	833.7	951.7	884.5
Probable	147.0	134.9	16.1	15.6	255.1	228.5	418.2	379.0
Total Proved Plus Probable	**168.3**	**153.9**	**48.9**	**47.4**	**1,152.6**	**1,062.2**	**1,369.9**	**1,263.5**

	Conventional Natural Gas *(bcf)*		Natural Gas Liquids *(mmbbls)*		Total *(mmboe)*	
	Gross	Net	Gross	Net	Gross	Net
Proved						
Developed Producing	1,184.0	1,059.1	47.5	40.6	419.9	381.0
Developed Non-producing	19.6	17.7	1.5	1.3	21.1	19.9
Undeveloped	187.5	157.4	8.3	7.5	799.8	738.7
Total Proved	1,391.1	1,234.2	57.3	49.4	1,240.8	1,139.5
Probable	420.6	371.5	24.1	20.7	512.4	461.6
Total Proved Plus Probable	**1,811.7**	**1,605.7**	**81.4**	**70.1**	**1,753.2**	**1,601.2**

Future Net Revenue Tables

Summary of Net Present Values of Future Net Revenue - Before Income Taxes and Discounted
As at December 31, 2020
Forecast Prices and Costs

Canada

	Before Income Taxes and Discounted at (%/year)					Unit Value Discounted at 10%
($ millions)	0 %	5 %	10 %	15 %	20 %	*($/boe)*
Proved						
Developed Producing	(3,176.6)	437.4	1,100.7	1,265.7	1,292.6	4.11
Developed Non-producing[(1)]	(193.0)	(113.8)	(77.9)	(57.5)	(44.9)	(3.92)
Undeveloped	10,655.4	3,720.6	1,614.5	745.2	314.0	2.21
Total Proved	7,285.8	4,044.3	2,637.3	1,953.3	1,561.7	2.59
Probable	8,754.3	5,568.6	3,566.7	2,339.0	1,563.9	8.04
Total Proved Plus Probable	**16,040.1**	**9,612.9**	**6,204.0**	**4,292.3**	**3,125.6**	**4.24**

(1) In the Heavy Oil properties there are approximately 9,000 oil and gas wells with no reserves assigned that carry surface land, maintenance and property taxes that also form part of each non-producing property's (that has reserves) operating costs. Accordingly, these costs have been included in the reserves reports in the Proved Developed Non-producing category.

China

	Before Income Taxes and Discounted at (%/year)					Unit Value Discounted at 10%
($ millions)	0 %	5 %	10 %	15 %	20 %	*($/boe)*
Proved						
Developed Producing	5,048.5	4,224.5	3,634.9	3,196.5	2,859.8	38.03
Developed Non-producing	—	—	—	—	—	—
Undeveloped	—	—	—	—	—	—
Total Proved	5,048.5	4,224.5	3,634.9	3,196.5	2,859.8	38.03
Probable	565.5	404.7	308.9	247.7	206.0	26.44
Total Proved Plus Probable	**5,614.0**	**4,629.2**	**3,943.8**	**3,444.1**	**3,065.9**	**36.77**

Indonesia

	Before Income Taxes and Discounted at (%/year)					Unit Value Discounted at 10%
($ millions)	0 %	5 %	10 %	15 %	20 %	*($/boe)*
Proved						
Developed Producing	435.5	372.4	324.3	286.9	257.2	18.16
Developed Non-producing	—	—	—	—	—	—
Undeveloped	240.9	193.2	156.7	128.4	106.0	21.07
Total Proved	676.4	565.6	481.0	415.3	363.2	19.01
Probable	178.7	117.8	80.1	56.1	40.4	13.16
Total Proved Plus Probable	**855.1**	**683.4**	**561.1**	**471.3**	**403.6**	**17.88**

Total

	Before Income Taxes and Discounted at (%/year)					Unit Value Discounted at 10%
($ millions)	0 %	5 %	10 %	15 %	20 %	*($/boe)*
Proved						
Developed Producing	2,307.5	5,034.4	5,059.9	4,749.1	4,409.7	13.28
Developed Non-producing[(1)]	(193.0)	(113.8)	(77.9)	(57.5)	(44.9)	(3.92)
Undeveloped	10,896.3	3,913.8	1,771.2	873.5	420.0	2.40
Total Proved	13,010.8	8,834.4	6,753.2	5,565.0	4,784.7	5.93
Probable	9,498.4	6,091.1	3,955.7	2,642.7	1,810.3	8.57
Total Proved Plus Probable	**22,509.2**	**14,925.4**	**10,708.8**	**8,207.8**	**6,595.1**	**6.69**

(1) In the Heavy Oil properties there are approximately 9,000 oil and gas wells with no reserves assigned that carry surface land, maintenance and property taxes that are part of each non-producing property's (that has reserves) operating costs. Accordingly, these costs have been included in the reserves reports in the Proved Developed Non-producing category.

Summary of Net Present Values of Future Net Revenue - After Income Taxes and Discounted
As at December 31, 2020
Forecast Prices and Costs

Canada

	After Income Taxes and Discounted at (%/year)				
($ millions)	0 %	5 %	10 %	15 %	20 %
Proved					
Developed Producing	(2,308.2)	352.7	832.2	948.1	964.7
Developed Non-producing[(1)]	(146.0)	(87.5)	(61.3)	(46.3)	(37.1)
Undeveloped	7,996.0	2,653.0	1,067.0	425.3	113.3
Total Proved	5,541.7	2,918.2	1,837.9	1,327.1	1,040.9
Probable	6,380.3	3,963.5	2,461.0	1,550.6	983.2
Total Proved Plus Probable	**11,922.0**	**6,881.7**	**4,299.0**	**2,877.7**	**2,024.1**

(1) In the Heavy Oil properties there are approximately 9,000 oil and gas wells with no reserves assigned that carry surface land, maintenance and property taxes that are part of each non-producing property's (that has reserves) operating costs. Accordingly, these costs have been included in the reserves reports in the Proved Developed Non-producing category.

China

	After Income Taxes and Discounted at (%/year)				
($ millions)	0 %	5 %	10 %	15 %	20 %
Proved					
Developed Producing	3,784.6	3,167.8	2,726.7	2,398.9	2,147.5
Developed Non-producing	—	—	—	—	—
Undeveloped	—	—	—	—	—
Total Proved	3,784.6	3,167.8	2,726.7	2,398.9	2,147.5
Probable	424.0	303.4	231.6	185.7	154.5
Total Proved Plus Probable	**4,208.5**	**3,471.2**	**2,958.3**	**2,584.6**	**2,301.9**

Indonesia

	After Income Taxes and Discounted at (%/year)				
($ millions)	0 %	5 %	10 %	15 %	20 %
Proved					
Developed Producing	289.5	255.5	228.5	206.6	188.8
Developed Non-producing	—	—	—	—	—
Undeveloped	165.9	133.4	108.3	88.6	73.0
Total Proved	455.4	388.9	336.7	295.3	261.8
Probable	79.4	54.3	38.1	27.5	20.3
Total Proved Plus Probable	**534.8**	**443.2**	**374.9**	**322.7**	**282.1**

Total

	After Income Taxes and Discounted at (%/year)				
($ millions)	0 %	5 %	10 %	15 %	20 %
Proved					
Developed Producing	1,765.8	3,776.0	3,787.4	3,553.7	3,300.9
Developed Non-producing[(1)]	(146.0)	(87.5)	(61.3)	(46.3)	(37.1)
Undeveloped	8,161.9	2,786.4	1,175.2	513.9	186.3
Total Proved	9,781.6	6,474.8	4,901.4	4,021.3	3,450.1
Probable	6,883.7	4,321.2	2,730.7	1,763.8	1,158.0
Total Proved Plus Probable	**16,665.3**	**10,796.0**	**7,632.1**	**5,785.1**	**4,608.1**

(1) In the Heavy Oil properties there are approximately 9,000 oil and gas wells with no reserves assigned that carry surface land, maintenance and property taxes that are part of each non-producing property's (that has reserves) operating costs. Accordingly, these costs have been included in the reserves reports in the Proved Developed Non-producing category.

Total Future Net Revenue for Total Proved Plus Probable Reserves - Undiscounted
As at December 31, 2020
Forecast Prices and Costs

($ millions)	Revenue	Royalties	Operating Costs	Development Costs	Abandonment and Reclamation Costs	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
Canada								
Total Proved	51,460.4	4,800.5	24,401.6	8,980.8	5,991.7	7,285.8	1,744.1	5,541.7
Total Proved Plus Probable	76,773.8	7,331.7	33,141.4	13,805.1	6,455.5	16,040.1	4,118.1	11,922.0
China								
Total Proved	6,953.0	377.0	1,367.9	—	159.6	5,048.5	1,264.0	3,784.6
Total Proved Plus Probable	7,727.1	418.9	1,534.2	—	160.0	5,614.0	1,405.5	4,208.5
Indonesia								
Total Proved	2,342.4	718.2	883.4	36.4	28.0	676.4	221.0	455.4
Total Proved Plus Probable	3,052.1	1,047.4	1,081.3	36.4	31.9	855.1	320.3	534.8
Total								
Total Proved	60,755.9	5,895.7	26,652.9	9,017.2	6,179.3	13,010.8	3,229.1	9,781.6
Total Proved Plus Probable	87,553.0	8,798.1	35,756.8	13,841.6	6,647.4	22,509.2	5,843.9	16,665.3

Future Net Revenue by Product Type
As at December 31, 2020
Forecast Prices and Costs

	Future Net Revenue Before Income Taxes (discounted at 10%/year)[1]							
	Canada		China		Indonesia		Total	
	($ millions)	*($/boe)*	*($ millions)*	*($/boe)*	*($ millions)*	*($/boe)*	*($ millions)*	*($/boe)*
Total Proved								
Light & Medium Crude Oil	45.7	0.65	—	—	—	—	45.7	0.65
Heavy Crude Oil	(394.1)	(12.12)	—	—	—	—	(394.1)	(12.12)
Bitumen	3,056.6	3.67	—	—	—	—	3,056.6	3.67
Total Oil	2,708.2	2.89	—	—	—	—	2,708.2	2.89
Conventional Natural Gas	(70.9)	(0.86)	3,634.9	38.03	481.0	19.01	4,045.0	19.89
Total Proved	**2,637.3**	**2.59**	**3,634.9**	**38.03**	**481.0**	**19.01**	**6,753.2**	**5.93**
Total Proved Plus Probable								
Light & Medium Crude Oil	474.9	2.27	—	—	—	—	474.9	2.27
Heavy Crude Oil	(183.5)	(3.79)	—	—	—	—	(183.5)	(3.79)
Bitumen	5,742.2	5.41	—	—	—	—	5,742.2	5.41
Total Oil	6,033.6	4.57	—	—	—	—	6,033.6	4.57
Conventional Natural Gas	170.3	1.19	3,943.8	36.77	561.1	17.88	4,675.2	16.62
Total Proved Plus Probable	**6,204.0**	**4.24**	**3,943.8**	**36.77**	**561.1**	**17.88**	**10,708.8**	**6.69**

[1] By-products, including solution gas, NGL and other associated by-products, are included in their main product group (conventional natural gas or oil).

Pricing Assumptions

Except as noted below, the pricing assumptions disclosed in the following table were derived using the industry averages prescribed by McDaniel and Associates Consultants Ltd., Sproule and GLJ Ltd. China and Indonesia gas prices are derived from the GSAs specific to each set of projects. For historical prices realized during 2020, see "Statement of Reserves Data and Other Oil and Gas Information - Disclosure of Oil and Gas Activities - Operating Netback Analysis".

	Light Crude Oil			Medium Crude Oil	Heavy Crude Oil
	WTI *(U.S. $/bbl)*	Brent *(U.S. $/bbl)*	Edmonton *(Cdn $/bbl)*	Hardisty Bow River *(Cdn $/bbl)*	Lloyd Heavy API *(Cdn $/bbl)*
Historical					
2020	39.40	41.70	45.34	35.78	30.28
Forecast					
2021	47.17	49.42	55.76	45.36	39.87
2022	50.17	52.85	59.89	48.96	43.20
2023	53.17	56.04	63.48	52.91	46.86
2024	54.97	57.87	65.76	54.95	48.67
2025	56.07	59.00	67.13	56.05	49.65
2026	57.19	60.15	68.53	57.16	50.65
2027	58.34	61.33	69.95	58.30	51.67
2028	59.50	62.53	71.40	59.47	52.71
2029	60.69	63.75	72.88	60.66	53.76
2030	61.91	65.03	74.34	61.87	54.84
Thereafter	2.00%/yr	2.00%/yr	2.00%/yr	2.00%/yr	2.00%/yr

	Bitumen	Conventional Natural Gas	Natural Gas Liquids		
	Hardisty WCS *(Cdn $/bbl)*	AECO *(Cdn $/GJ)*	Edmonton Propane *(Cdn $/bbl)*	Edmonton Butane *(Cdn $/bbl)*	Edmonton Condensate *(Cdn $/bbl)*
Historical					
2020	35.94	2.12	16.26	22.06	49.45
Forecast					
2021	44.63	2.63	18.18	26.36	59.24
2022	48.18	2.56	21.91	32.85	63.19
2023	52.10	2.48	24.57	39.20	67.34
2024	54.10	2.51	25.47	40.65	69.77
2025	55.19	2.56	26.00	41.50	71.18
2026	56.29	2.61	26.54	42.36	72.61
2027	57.42	2.66	27.09	43.24	74.07
2028	58.57	2.72	27.65	44.14	75.56
2029	59.74	2.77	28.23	45.06	77.08
2030	60.93	2.82	28.79	45.96	78.62
Thereafter	2.00%/yr	2.00%/yr	2.00%/yr	2.00%/yr	2.00%/yr

	Asia Pacific			
	China	Indonesia		
	Conventional Natural Gas *(U.S. $/mcf)*(1)	Conventional Natural Gas *(U.S. $/mcf)*(1)	Inflation rates(2)	Exchange rates(3)
Historical				
2020	10.12	7.48	0.87	0.75
Forecast				
2021	8.98	7.53	—	0.77
2022	9.18	7.32	1.33	0.77
2023	8.96	7.17	2.00	0.76
2024	9.02	7.30	2.00	0.76
2025	9.08	7.44	2.00	0.76
2026	9.17	7.54	2.00	0.76
2027	9.22	7.68	2.00	0.76
2028	9.04	7.84	2.00	0.76
2029	8.93	7.92	2.00	0.76
2030	8.72	8.04	2.00	0.76
Thereafter			2.00	0.76

(1) Conventional natural gas prices in China and Indonesia have been updated from the prior year values due to changes in exchange rates and are the volume weighted average based on the various GSAs.
(2) Inflation rates represent a percentage for forecasting costs.
(3) Exchange rates used to generate the benchmark reference prices are quoted in U.S. dollar to Canadian dollar.

Reconciliation of Gross Proved Reserves

	Light & Medium Crude Oil *(mmbbls)*	Heavy Crude Oil *(mmbbls)*	Bitumen *(mmbbls)*	Total Oil *(mmbbls)*	Conventional Natural Gas *(bcf)*	Natural Gas Liquids *(mmbbls)*	Total *(mmboe)*
Canada - Western Canada							
End of 2019	18.3	46.6	943.3	1,008.3	815.0	56.6	1,200.7
Technical Revisions	(0.4)	0.3	(9.2)	(9.3)	(83.2)	(18.0)	(41.2)
Economic Factors	(1.5)	(8.8)	(2.9)	(13.1)	(14.0)	(1.0)	(16.4)
Acquisitions	—	—	—	—	—	—	—
Dispositions	(0.5)	—	—	(0.5)	(10.3)	(0.4)	(2.6)
Discoveries	—	—	—	—	—	—	—
Extensions & Improved Recovery	0.3	3.0	10.9	14.1	88.7	2.0	30.9
Production	(2.1)	(8.3)	(44.6)	(55.0)	(95.6)	(3.7)	(74.7)
End of 2020	**14.1**	**32.8**	**897.5**	**944.5**	**700.8**	**35.5**	**1,096.7**
Canada - Atlantic							
End of 2019	84.9	—		84.9	—	—	84.9
Technical Revisions	(7.1)	—	—	(7.1)	—	—	(7.1)
Economic Factors	(64.1)	—	—	(64.1)	—	—	(64.1)
Acquisitions	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	—	—	—	—
Production	(6.4)	—	—	(6.4)	—	—	(6.4)
End of 2020	**7.3**	**—**	**—**	**7.3**	**—**	**—**	**7.3**
China							
End of 2019	—	—	—	—	495.8	17.0	99.7
Technical Revisions	—	—	—	—	71.3	3.7	15.6
Economic Factors	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	—	—	—	—
Production	—	—	—	—	(73.7)	(3.2)	(15.4)
End of 2020	**—**	**—**	**—**	**—**	**493.3**	**17.6**	**99.8**
Indonesia							
End of 2019	—	—	—	—	241.6	5.1	45.4
Technical Revisions	—	—	—	—	(32.1)	—	(5.3)
Economic Factors	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	—	—	—	—
Production	—	—	—	—	(12.6)	(0.9)	(3.0)
End of 2020	**—**	**—**	**—**	**—**	**197.0**	**4.3**	**37.1**

	Light & Medium Crude Oil *(mmbbls)*	Heavy Crude Oil *(mmbbls)*	Bitumen *(mmbbls)*	Total Oil *(mmbbls)*	Conventional Natural Gas *(bcf)*	Natural Gas Liquids *(mmbbls)*	Total *(mmboe)*
Total							
End of 2019	103.2	46.6	943.3	1,093.2	1,552.4	78.8	1,430.7
Technical Revisions	(7.5)	0.3	(9.2)	(16.4)	(44.0)	(14.3)	(38.1)
Economic Factors	(65.6)	(8.8)	(2.9)	(77.3)	(14.0)	(1.0)	(80.6)
Acquisitions	—	—	—	—	—	—	—
Dispositions	(0.5)	—	—	(0.5)	(10.3)	(0.4)	(2.6)
Discoveries	—	—	—	—	—	—	—
Extensions & Improved Recovery	0.3	3.0	10.9	14.1	88.7	2.0	30.9
Production	(8.5)	(8.3)	(44.6)	(61.5)	(181.9)	(7.8)	(99.6)
End of 2020	**21.4**	**32.8**	**897.5**	**951.7**	**1,391.1**	**57.3**	**1,240.8**

At December 31, 2020, the Company's proved oil and gas reserves were 1,241 mmboe, down from 1,431 mmboe at the end of 2019. The Company's 2020 reserves replacement ratio, defined as net changes to proved reserves divided by total production during the period, was negative 10% excluding economic revisions (negative 91% including economic revisions).

Major changes to proved reserves in 2020 included:

- Western Canada Extensions & Improved Recovery additions of 31 mmboe associated with 17 mmboe from Western Canada conventional natural gas including new locations (89 bcf of conventional natural gas and 2 mmbbls of NGL), 11 mmbbls primarily from Sunrise, and 3 mmbbls mainly from cold heavy crude oil production new drills.
- Net negative technical revisions in Canada of 48 mmboe mainly associated with 32 mmboe of conventional natural gas and associated NGL revisions (negative 83 bcf conventional natural gas and 18 mmbbls of NGL), primarily due to performance analysis and revised development plans in response to current market conditions. An additional 9 mmboe negative technical revisions of bitumen are mainly from Sunrise due to deferred capital plans. Net negative technical revisions of 7 mmboe in Atlantic are primarily due to the Terra Nova suspension causing a transfer to probable, offset by positive performance in White Rose.
- Net positive technical revisions for offshore China of 16 mmboe (71 bcf conventional natural gas and 4 mmbbls of NGL) mainly due to transfers from probable and the expanded GSA in Liwan 3-1. Net negative technical revisions in Indonesia of 5 mmboe (32 bcf of conventional natural gas) are due to expiring agreements, which are currently being renegotiated, associated with project delays.
- Economic factors reduction of 81 mmboe associated with significantly lower oil prices in North America. As a result, the West White Rose Project proved reserves were transferred to probable. Cold heavy crude oil reserves were reduced by 9 mmbbls as a result of economics and shut-in wells.

Reconciliation of Gross Probable Reserves

	Light & Medium Crude Oil *(mmbbls)*	Heavy Crude Oil *(mmbbls)*	Bitumen *(mmbbls)*	Total Oil *(mmbbls)*	Conventional Natural Gas *(bcf)*	Natural Gas Liquids *(mmbbls)*	Total *(mmboe)*
Canada - Western Canada							
End of 2019	7.7	19.0	422.3	449.0	339.4	43.7	549.3
Technical Revisions	(4.3)	(2.4)	(167.2)	(173.9)	(139.4)	(26.8)	(224.0)
Economic Factors	(0.2)	(1.1)	(1.0)	(2.3)	(2.5)	(0.1)	(2.8)
Acquisitions	—	—	—	—	—	—	—
Dispositions	(0.1)	—	—	(0.1)	(1.2)	—	(0.3)
Discoveries	—	—	—	—	—	—	—
Extensions & Improved Recovery	—	0.6	1.0	1.7	105.3	3.7	22.9
Production	—	—	—	—	—	—	—
End of 2020	**3.1**	**16.1**	**255.1**	**274.4**	**301.6**	**20.5**	**345.1**
Canada - Atlantic							
End of 2019	84.1	—	—	84.1	—	—	84.1
Technical Revisions	(4.4)	—	—	(4.4)	—	—	(4.4)
Economic Factors	64.1	—	—	64.1	—	—	64.1
Acquisitions	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	—	—	—	—
Production	—	—	—	—	—	—	—
End of 2020	**143.8**	**—**	**—**	**143.8**	**—**	**—**	**143.8**
China							
End of 2019	—	—	—	—	119.5	4.5	24.4
Technical Revisions	—	—	—	—	(56.9)	(2.6)	(12.0)
Economic Factors	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	—	—	—	—
Production	—	—	—	—	—	—	—
End of 2020	**—**	**—**	**—**	**—**	**62.5**	**1.9**	**12.3**
Indonesia							
End of 2019	—	—	—	—	91.5	1.6	16.9
Technical Revisions	—	—	—	—	(35.0)	0.1	(5.8)
Economic Factors	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	—	—	—	—
Production	—	—	—	—	—	—	—
End of 2020	**—**	**—**	**—**	**—**	**56.5**	**1.7**	**11.1**

	Light & Medium Crude Oil *(mmbbls)*	Heavy Crude Oil *(mmbbls)*	Bitumen *(mmbbls)*	Total Oil *(mmbbls)*	Conventional Natural Gas *(bcf)*	Natural Gas Liquids *(mmbbls)*	Total *(mmboe)*
Total							
End of 2019	91.8	19.0	422.3	533.1	550.4	49.8	674.7
Technical Revisions	(8.7)	(2.4)	(167.2)	(178.3)	(231.3)	(29.3)	(246.2)
Economic Factors	63.9	(1.1)	(1.0)	61.8	(2.5)	(0.1)	61.3
Acquisitions	—	—	—	—	—	—	—
Dispositions	(0.1)	—	—	(0.1)	(1.2)	—	(0.3)
Discoveries	—	—	—	—	—	—	—
Extensions & Improved Recovery	—	0.6	1.0	1.7	105.3	3.7	22.9
Production	—	—	—	—	—	—	—
End of 2020	**147.0**	**16.1**	**255.1**	**418.2**	**420.6**	**24.1**	**512.4**

Major changes to probable reserves in 2020 included:

- Western Canada Extensions & Improved Recovery additions to natural gas resource plays of 105 bcf of conventional natural gas and 4 mmbbls of NGL including new locations.
- Bitumen technical revisions in Western Canada of negative 167 mmboe primarily due to the removal of expansion projects and associated locations that are no longer funded in the next five years at Sunrise and an existing Lloydminster SAGD project. Further revisions include revised mapping and performance analysis with updated information in Sunrise, Tucker and two existing Lloydminster SAGD projects.
- Conventional natural gas and associated NGL revisions in Western Canada of negative 50 mmboe (139 bcf conventional natural gas and 27 mmbbls of NGL) primarily due to revised development plans in response to current market conditions and performance analysis.
- Positive economic factors of 61 mmboe mainly associated with West White Rose Project proved reserves being transferred to probable as a result of significantly lower oil prices in North America.
- Asia Pacific negative technical revisions due to transfers from probable into proved for offshore China and expiring agreements, which are currently being renegotiated, associated with project delays in Indonesia.

Reconciliation of Gross Proved Plus Probable Reserves

	Light & Medium Crude Oil *(mmbbls)*	Heavy Crude Oil *(mmbbls)*	Bitumen *(mmbbls)*	Total Oil *(mmbbls)*	Conventional Natural Gas *(bcf)*	Natural Gas Liquids *(mmbbls)*	Total *(mmboe)*
Canada - Western Canada							
End of 2019	26.0	65.7	1,365.6	1,457.3	1,154.4	100.3	1,750.0
Technical Revisions	(4.7)	(2.1)	(176.4)	(183.3)	(222.6)	(44.8)	(265.2)
Economic Factors	(1.7)	(9.9)	(3.9)	(15.5)	(16.5)	(1.0)	(19.3)
Acquisitions	—	—	—	—	—	—	—
Dispositions	(0.6)	—	—	(0.6)	(11.4)	(0.5)	(2.9)
Discoveries	—	—	—	—	—	—	—
Extensions & Improved Recovery	0.4	3.6	11.9	15.8	194.0	5.7	53.9
Production	(2.1)	(8.3)	(44.6)	(55.0)	(95.6)	(3.7)	(74.7)
End of 2020	**17.3**	**48.9**	**1,152.6**	**1,218.8**	**1,002.3**	**56.0**	**1,441.9**
Canada - Atlantic							
End of 2019	169.1	—	—	169.1	—	—	169.1
Technical Revisions	(11.5)	—	—	(11.5)	—	—	(11.5)
Economic Factors	(0.1)	—	—	(0.1)	—	—	(0.1)
Acquisitions	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	—	—	—	—
Production	(6.4)	—	—	(6.4)	—	—	(6.4)
End of 2020	**151.1**	**—**	**—**	**151.1**	**—**	**—**	**151.1**
China							
End of 2019	—	—	—	—	615.2	21.5	124.0
Technical Revisions	—	—	—	—	14.3	1.1	3.5
Economic Factors	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	—	—	—	—
Production	—	—	—	—	(73.7)	(3.2)	(15.4)
End of 2020	**—**	**—**	**—**	**—**	**555.9**	**19.5**	**112.1**
Indonesia							
End of 2019	—	—	—	—	333.1	6.8	62.3
Technical Revisions	—	—	—	—	(67.1)	—	(11.1)
Economic Factors	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	—	—	—	—
Production	—	—	—	—	(12.6)	(0.9)	(3.0)
End of 2020	**—**	**—**	**—**	**—**	**253.5**	**5.9**	**48.2**

	Light & Medium Crude Oil *(mmbbls)*	Heavy Crude Oil *(mmbbls)*	Bitumen *(mmbbls)*	Total Oil *(mmbbls)*	Conventional Natural Gas *(bcf)*	Natural Gas Liquids *(mmbbls)*	Total *(mmboe)*
Total							
End of 2019	195.0	65.7	1,365.6	1,626.3	2,102.8	128.6	2,105.4
Technical Revisions	(16.2)	(2.1)	(176.4)	(194.8)	(275.3)	(43.7)	(284.3)
Economic Factors	(1.7)	(9.9)	(3.9)	(15.5)	(16.5)	(1.0)	(19.3)
Acquisitions	—	—	—	—	—	—	—
Dispositions	(0.6)	—	—	(0.6)	(11.4)	(0.5)	(2.9)
Discoveries	—	—	—	—	—	—	—
Extensions & Improved Recovery	0.4	3.6	11.9	15.8	194.0	5.7	53.9
Production	(8.5)	(8.3)	(44.6)	(61.5)	(181.9)	(7.8)	(99.6)
End of 2020	**168.3**	**48.9**	**1,152.6**	**1,369.9**	**1,811.7**	**81.4**	**1,753.2**

Undeveloped Reserves

Undeveloped reserves are attributed internally in accordance with standards and procedures contained in the COGEH. Proved undeveloped oil and gas reserves are those reserves that can be estimated with a high degree of certainty to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Probable undeveloped oil and gas reserves are those reserves that are less certain to be recovered than proved reserves and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. There are numerous uncertainties inherent in estimating quantities of crude oil and conventional natural gas reserves. Classifications of reserves as proved or probable are only attempts to define the degree of uncertainty associated with the estimates. In addition, whereas proved reserves are those reserves that can be estimated with a high degree of certainty to be economically producible, probable reserves are those reserves that are as likely as not to be recovered. Therefore, probable reserves estimates, by definition, have a higher degree of uncertainty than proved reserves.

Approximately 54% of Husky's gross proved undeveloped reserves are assigned to the Sunrise Energy Project. Production from Phase I of the project started in March 2015, and wells will be drilled in the future to keep the plant at full capacity. Approximately 39% of Husky's gross proved undeveloped reserves are assigned to 12 heavy oil thermal projects in the Lloydminster area that are classified as bitumen. Approximately 4% of Husky's gross proved undeveloped reserves are assigned to Ansell and Wembley gas resource plays.

Husky has funded capital programs by cash generated from operating activities, cash on hand, equity issuances and short-term and long-term debt. Decisions on the priority and timing of developing the various proved undeveloped and probable undeveloped reserves, including decisions to defer development of proved undeveloped reserves beyond two years, are based on various factors including strategic considerations, changing economic conditions, changes to government regulations including the setting of production limits, technical performance, development plan optimization, facility capacity, pipeline constraints, and the size of the development program. The development opportunities have been pursued at a pace dependent on capital availability and its allocation in accordance with Husky's business plans.

As at December 31, 2020, there were no material proved undeveloped reserves that have remained undeveloped for greater than five years, except as follows. The Sunrise Energy Project proved and probable undeveloped bitumen reserves are scheduled to be developed and produced over the next 50 years to fully utilize the steam plant and processing capacity over the life of the current facilities. The Spruce Lake North thermal bitumen project not yet on production is scheduled to start up in 2024. The Lloydminster thermals and Tucker bitumen proved and probable undeveloped locations for existing facilities are scheduled to be developed over the next one to 25 years to utilize each project's steam and processing capacities. The West White Rose Project is scheduled to have the first probable undeveloped locations placed on production by 2024. Proved undeveloped reserves in Madura are scheduled to be brought on production in 2022. Wembley and Ansell's proved and probable undeveloped locations are scheduled to be developed over the next five and seven years, respectively, in accordance with the Company's development plan.

Proved Undeveloped Reserves

	Light & Medium Crude Oil *(mmbbls)*		Heavy Crude Oil *(mmbbls)*		Bitumen *(mmbbls)*		Total Oil *(mmbbls)*	
	First Attributed	Total at year-end	First Attributed	Total at year-end	First Attributed	Total at year-end	First Attributed	Total at year-end
2018	8.4	69.8	1.0	1.0	177.3	747.9	186.6	818.6
2019	2.8	66.4	1.3	1.3	109.9	775.0	113.9	842.7
2020	**—**	**—**	**1.1**	**1.1**	**10.9**	**759.2**	**12.0**	**760.3**

	Conventional Natural Gas *(bcf)*		Natural Gas Liquids *(mmbbls)*		Total *(mmboe)*	
	First Attributed	Total at year-end	First Attributed	Total at year-end	First Attributed	Total at year-end
2018	310.4	739.1	9.2	12.4	247.6	954.2
2019	133.1	367.6	18.3	23.1	154.5	927.1
2020	**67.5**	**187.5**	**1.3**	**8.3**	**24.6**	**799.8**

Probable Undeveloped Reserves

	Light & Medium Crude Oil *(mmbbls)*		Heavy Crude Oil *(mmbbls)*		Bitumen *(mmbbls)*		Total Oil *(mmbbls)*	
	First Attributed	Total at year-end	First Attributed	Total at year-end	First Attributed	Total at year-end	First Attributed	Total at year-end
2018	0.7	71.2	1.9	2.2	265.6	778.4	268.2	851.8
2019	3.4	65.4	4.2	4.2	20.9	368.9	28.4	438.4
2020	**—**	**115.3**	**0.2**	**3.3**	**1.0**	**199.5**	**1.2**	**318.1**

	Conventional Natural Gas *(bcf)*		Natural Gas Liquids *(mmbbls)*		Total *(mmboe)*	
	First Attributed	Total at year-end	First Attributed	Total at year-end	First Attributed	Total at year-end
2018	139.0	472.2	4.9	7.8	296.2	938.3
2019	224.9	348.8	37.0	39.7	102.9	536.3
2020	**97.3**	**220.6**	**3.2**	**15.7**	**20.6**	**370.6**

Significant Factors or Uncertainties Affecting Reserves Data

Husky's reserves can be affected significantly by material fluctuations in product pricing, development plans and capital expenditures, operating costs, regulatory changes that impact costs and/or royalties and production performance. Actual product prices may vary significantly from the forecast price assumptions used by the Company to estimate its reserves, altering the allocation and level of capital expenditures, and accelerating or delaying project schedules. As new information is obtained, the above factors that affect costs, royalties and production performance are reviewed and updated accordingly, which may result in positive or negative revisions to reserves. The effective date of the reserves estimates in this AIF is December 31, 2020, which was prior to completion of the Cenovus Transaction. As a result of the Cenovus Transaction, the Company's development plans and capital expenditure plans may change as Husky and Cenovus integrate their operations, which changes may impact the Company's reserves estimates. For additional information on risk factors please see "Risk Factors - Reservoir Performance and Reserves Estimates Risk."

There are no significant abandonment or reclamation costs, no unusually high expected development costs or operating costs and no contractual obligations to produce and sell a significant portion of production at prices substantially below those which could be realized but for those contractual obligations that have affected, or that the Company reasonably expects to affect, anticipated development or production activities on properties with reserves. For further information on abandonment and reclamation costs in respect of the Company's properties, please refer to Note 18 of the Company's audited consolidated financial statements as at and for the year ended December 31, 2020.

Future Development Costs

With the completion of the Cenovus Transaction, the Company expects to fund its future development costs by cash generated from operating activities, cash on hand, credit facilities and short and long-term debt of the combined company. The cost associated with the combined company's credit facilities and short and long-term debt would not affect reserves and would not be material in comparison with future net revenues.

The following table includes estimates of the forecasted costs of developing the Company's proved and proved plus probable reserves as at December 31, 2020:

	Canada		China		Indonesia		Total	
Year	Proved Reserves *($ millions)*	Proved Plus Probable Reserves *($ millions)*	Proved Reserves *($ millions)*	Proved Plus Probable Reserves *($ millions)*	Proved Reserves *($ millions)*	Proved Plus Probable Reserves *($ millions)*	Proved Reserves *($ millions)*	Proved Plus Probable Reserves *($ millions)*
2021	272.0	442.8	—	—	12.9	12.9	284.9	455.7
2022	350.0	1,046.6	—	—	23.5	23.5	373.5	1,070.1
2023	435.1	1,120.7	—	—	—	—	435.1	1,120.7
2024	365.7	1,197.2	—	—	—	—	365.7	1,197.2
2025	459.6	831.6	—	—	—	—	459.6	831.6
Remaining	7,098.4	9,166.2	—	—	—	—	7,098.4	9,166.2
Total	**8,980.8**	**13,805.1**	**—**	**—**	**36.4**	**36.4**	**9,017.2**	**13,841.6**

Production Estimates

Yearly Production Estimates for 2021

	Light & Medium Crude Oil *(mbbls/day)*	Heavy Crude Oil *(mbbls/day)*	Bitumen *(mbbls/day)*	Total Oil *(mbbls/day)*	Conventional Natural Gas *(mmcf/day)*	Natural Gas Liquids *(mbbls/day)*	Total *(mboe/day)*
Canada							
Total Gross Proved	16.6	18.3	116.6	151.5	218.6	8.7	196.7
Total Gross Probable	1.8	2.1	17.4	21.3	10.8	0.6	23.6
Total Gross Proved Plus Probable	**18.5**	**20.3**	**134.0**	**172.8**	**229.4**	**9.3**	**220.3**
China							
Total Gross Proved	—	—	—	—	234.7	9.2	48.3
Total Gross Probable	—	—	—	—	4.6	0.2	1.0
Total Gross Proved Plus Probable	**—**	**—**	**—**	**—**	**239.3**	**9.4**	**49.3**
Indonesia							
Total Gross Proved	—	—	—	—	38.4	2.5	8.9
Total Gross Probable	—	—	—	—	—	—	—
Total Gross Proved Plus Probable	**—**	**—**	**—**	**—**	**38.4**	**2.5**	**8.9**
Total							
Total Gross Proved	16.6	18.3	116.6	151.5	491.6	20.4	253.9
Total Gross Probable	1.8	2.1	17.4	21.3	15.4	0.8	24.6
Total Gross Proved Plus Probable	**18.5**	**20.3**	**134.0**	**172.8**	**507.1**	**21.2**	**278.5**

No individual property accounts for 20% or more of the estimated production disclosed.

Environmental, Social and Governance Considerations

Environmental, Social and Governance Policies

In 2020, Husky had a corporate Health, Safety and Environment Policy that affirmed its commitment to operational integrity. Operational integrity at Husky has meant conducting all activities in a responsible, safe and reliable manner so that there is no harm to people, the public is protected, impact to the environment is minimized, the health and wellbeing of employees is safeguarded, contractors and customers are safe and physical assets (such as facilities and equipment) and reputation are protected from damage and loss. Husky management has also monitored environmental, social and governance ("**ESG**") risks and reported to the Board through management's Enterprise Risk Management Framework.

In 2020, the HS&E Committee was responsible for oversight of the Health, Safety and Environment Policy, oversight of audit results and monitoring compliance with Husky's environmental policies, key performance indicators and regulatory requirements.

Authority for overall management of the Company's ESG strategy, including climate, has been the responsibility of Husky's Chief Executive Officer, who has delegated management of the Company's ESG vision and goals to the Chair of the ESG Steering Committee, which is the Senior Vice President, Corporate Affairs and Human Resources. The ESG Steering Committee has also been responsible for the Company's ESG disclosure strategy and ensuring compliance with Husky's governance model, including providing ESG information to the Company's Compliance and Risk Committee, which has then reported to the Board. In 2020, the Chair of the ESG Steering Committee reported to the Board on ESG matters, including climate, through the Corporate Governance Committee, which reviewed ESG matters as a standing item on its meeting agenda.

Husky's HS&E strategy and objectives have been set by the Executive Health, Safety and Environment Committee ("**EHSEC**"), which has maintained oversight of the elements of the Company's Enterprise Risk Matrix related to HS&E, including Climate-Related Risks and Air Emissions. The EHSEC has been the highest-level management committee with a mandate to provide executive level oversight and strategic direction for all critical HS&E issues, including regulatory and operational compliance relating to HS&E matters. This included operational climate-related issues, as these have been identified as a critical risk in the Enterprise Risk Matrix. In 2020, the EHSEC consisted of members of senior management (Vice President and above), and was chaired by the Senior Vice President, Safety, Operations Integrity and Environment. In 2020, the Audit Committee reviewed Husky's risk register quarterly.

In 2020, Husky's ESG strategy was integrated with its business plans and Enterprise Risk Matrix and aligned with the Husky Operational Integrity Management System ("**HOIMS**").

As a result of the Cenovus Transaction, the Company's ESG and HS&E strategy may change as Husky and Cenovus integrate their operations, which may impact the Company's existing policies and objectives.

Husky is committed to conducting business ethically, and in compliance with applicable laws, as well as upholding high standards of business integrity. Husky seeks to deter wrongdoing and promote transparent, honest and ethical behaviour in all its business dealings. Husky has a Code of Business Conduct (the "**Code**") that is compliant with the International Chamber of Commerce ("**ICC**") Rules of Conduct and Recommendations to Combat Extortion and Bribery, and sets out the standards employees, including temporary and contract staff, officers and directors are expected to meet. This policy includes sections on compliance with laws, avoidance of conflict of interest, proper record- keeping, political contributions, safeguarding company resources, fair competition, avoidance of bribery or other offerings of improper payments, guidelines on accepting payments and entertainment, and other matters. The Code is available on the Company's website at www.huskyenergy.com and on the SEDAR website at www.sedar.com.

Husky has established an anonymous and confidential online reporting tool and toll-free telephone numbers (the "**Ethics Help Line**") for employees, contractors and other stakeholders to report perceived breaches of the Code. The Ethics Help Line is hosted by EthicsPoint, an independent service provider. Information from submissions is captured and submitted anonymously to an Ethics Help Line committee made up of legal, audit, security, HS&E, and human resources personnel.

Husky's Anti-Bribery & Anti-Corruption Policy reinforces the Code with additional guidance regarding applicable anti-bribery and anti-corruption laws. All officers and employees, including temporary and contract staff, are expected to observe the highest standards of honesty, integrity, diligence and fairness in all business activities, and undertake mandatory annual training.

Husky and its personnel conduct business in many nations around the world and are subject to various sanctions and anti-money laundering laws. Husky's Sanctions & Anti-Money Laundering Policy applies to Husky and all of its subsidiaries and to all officers and employees including temporary and contract staff.

Husky's Government Relations Policy sets out a transparent approach to government relations including roles and responsibilities on engagement and advocacy with governments for participation in industry and business associations for Husky personnel, including officers, directors, employees, and independent and third-party contractors. The Government Relations Policy also reinforces Husky's prohibition on political contributions and sets clear parameters for employee's personal political participation and associated reporting requirements.

Husky complies with competition laws, the purpose of which are to preserve and promote a competitive market. Husky's Competition Act Compliance Policy assists Husky's directors, officers and employees by providing relevant information about competition laws and guidelines to follow to ensure these laws are complied with and that any issues are handled appropriately.

Husky is an equal opportunity employer dedicated to an environment free of discrimination, harassment and violence and where respectful treatment is the norm. Husky's Diversity and Respectful Workplace Policy applies to all employees and contractors.

As a responsible member of the communities in which it operates, Husky has a Corporate Citizenship Program that supports investments to reputable and eligible organizations aligned to strategic goals, priorities and values. Husky's Community Investment Policy provides guidance with the general goal of ensuring that contributions under the Corporate Citizenship Program are supported by a consistent and rigorous decision-making process and reflect Husky's core corporate values and business strategy.

Through the Corporate Citizenship Program, Husky's Scholarship Program encourages the pursuit of advanced education by providing financial assistance to qualified students pursuing post-secondary studies at eligible post-secondary educational institutions. The Scholarship Program supports the principles of diversity and inclusion at Husky by creating opportunities for specific and general populations, to prepare for a career in the energy sector.

Husky values education and professional development and provides employees with opportunities to continue to develop and advance their skills, knowledge and experience. Husky's Learning and Development Policy sets out guidelines, eligibility and support for employees.

Husky believes in securing and protecting personnel, physical assets, property and information from criminal, hostile or malicious acts, consistent with its Security Policy. This policy aims to reduce exposure to security risks with the general goal of ensuring the consistent application of security measures within Husky.

Husky is also committed to the safety of all personnel, the public and the environment when handling and transporting dangerous substances classified as dangerous goods. Husky's Transportation of Dangerous Goods ("TDG") policy ensures dangerous goods are transported in compliance with all TDG laws and Husky standards and procedures.

Husky is committed to ensuring health and safety at work. The ability of every employee and contractor to perform his or her particular job duties satisfactorily and safely is critical to Husky's continued success. Husky recognizes that the use of illicit drugs and other mood-altering substances, and the inappropriate use of alcohol and medications, can have serious adverse effects on job performance and ultimately on the safety and well-being of employees, contractors, customers, the public and the environment. In light of this, and the safety-sensitive nature of Husky's operations, Husky's Alcohol and Drug Policy outlines the standards and expectations associated with alcohol and other drug use, consistent with Husky's overall safety culture. In October 2019, edible cannabis, cannabis extracts and cannabis topicals became legal in Canada and are now being sold under the *Cannabis Act* (Canada). As such, Husky has clarified its Alcohol and Drug Policy to include cannabis edibles, extracts and topicals, and to provide ongoing clarity that misuse of and presence at work while under the influence of legalized cannabis in all its forms is prohibited.

The aforementioned policies have been available to employees and contractors on Husky's intranet. Communication of the policies has been provided through direct e-mail and articles published on Husky's intranet. Mandatory training has been provided as relevant to the policy and the individual's role via various mechanisms including in-class, web-based and self-serve courses.

Husky Operational Integrity Management System

Husky has managed operational risks by designing and building its facilities and conducting its operations in a safe and reliable manner. HOIMS is an interrelated framework that set the minimum requirements for all Husky operated entities. HOIMS established standards and procedures that provided a systematic way for Husky to identify, assess and control safety and operational integrity hazards as well as associated environmental risks integral to safe operations and protecting the environment. Risk registers, emergency preparedness, business continuity and security programs are in place for all operating areas. In January 2020, Husky launched the updated HOIMS 2.0.

The fundamental elements of HOIMS 2.0 are:

Leadership and Accountability
- Leaders manage the risks associated with their respective business activities. They are role models who are competent, visible, purposeful and systematic.

Training and Competency
- Personnel are trained and competent to perform their role responsibilities.

Risk Management
- Hazards are identified, and associated risks assessed, managed and prioritized to prevent incidents.

Operational Integrity Information
- Operational integrity and process safety information is accurate, current and easily accessible

Operating Procedures, Policies and Standards
- HOIMS entities document, maintain and follow operating procedures and standards to meet operational integrity goals.

Management of Change
- Risks associated with permanent, temporary and emergency changes that impact HSE and operational integrity are managed.

Emergency Management
- Husky is prepared to manage an emergency, business interruption or security event.

Incident Reporting, Recording, Investigation and Learning
- Report, investigate and learn from Husky incidents and other external high-impact incidents to prevent recurrence.

Safety Control of Work
- Formal processes are in place to allow work to be completed safety. Work includes upstream, midstream and downstream operations, well, logistics, maintenance, inspection, construction and decommissioning activities.

Project Delivery
- Facilities are designed and built, and assets are developed to meet business, HSE and operational integrity requirements.

Supply Chain and Contractor Management
- Supplied services and materials meet Husky's HS&E and operational integrity requirements.

Asset Operation
- Husky's assets and equipment are operated to meet operational integrity goals, preventing injury to people and damage to the environment

Reliability and Integrity
- Reliability and integrity are achieved and improved.

Regulatory Compliance
- Protect Husky's privilege to operate through verifying compliance with legal and regulatory, environmental and social governance requirements.

Assurance, Performance and Improvement
- Performance meets HS&E and operational integrity goals and objectives, and continuously improves.

Pipeline Integrity

The Company has a risk-based Pipeline Integrity Management ("**PIM**") Program which is implemented across all Husky-owned and operated pipelines. The PIM program is a framework supported by a suite of documents, including the Pipeline Operations and Maintenance ("**POMM**") Procedures Manual, which provides guidelines on safe operation and maintenance of pipelines. Numerous processes are implemented throughout the pipeline lifecycle to ensure a proactive approach to managing the integrity, operations, and maintenance of the pipeline.

The major processes of managing pipeline integrity include:

- A risk management program, which is used to identify integrity threats throughout the pipeline lifecycle and the risk associated with each threat. Appropriate measures are taken to address these risks and reduce them to an acceptable level.
- A Geohazard Integrity Management Program, which is used to identify and manage the risks associated with any potential geohazards (geotechnical and hydrotechnical) on pipelines.
- Technology improvements such as fiber optic sensing technology, advanced technologies for flood monitoring at water crossings, satellite monitoring for landslides, and in-line visual inspection for high-consequence pipelines.
- Engineering assessment, which involves the evaluation of the fitness for service of pipelines when changes are made to design parameters and at line reactivation to proactively mitigate the risk to operational integrity.
- Incident investigation, which is used to establish the root cause(s) of a failure and use this knowledge to proactively enhance pipeline safety and integrity, and to improve integrity programs.
- Annual pipeline integrity reviews, which are conducted for all pipeline systems to review the effectiveness of integrity programs and, where applicable, make recommendations for improvement.

- Training, including Husky's well-established Learning Management System, which defines training and experience requirements for the employees who are engaged in maintaining asset integrity. Husky also has a web-based PIM training program for all employees involved in the operation and maintenance of pipelines.
- Performance targets, which have been set annually and tracked quarterly. Immediate steps are taken to address any deficiencies.
- A Management of Change process, which is followed for any changes that affect pipeline operational integrity.
- POMM self-assessments, which are conducted to identify any gaps between POMM requirements and actual practices, and steps are taken to address these gaps.
- A PIM Program review, which is a regular review of the PIM program and supporting procedures for alignment with the latest code and regulatory requirements, taking into consideration Husky experience and pipeline industry standards and practices.

Climate Change

General

Along with increased evidence and effects of climate change, concerns about climate change and its solutions have increased significantly in recent years. Technology related to managing man-made GHG emissions, a source of climate change, is improving and expectations regarding climate change risk management are growing, resulting in increased stakeholder, investor and consumer pressure to reduce carbon emissions and transition to a net zero carbon future. Third parties have initiated litigation related to climate change against certain oil and gas companies and governments around the world. Some oil and gas companies have set net zero carbon emissions targets in response to one or more of these pressures.

The current regulatory environment related to air emissions and climate policy is also dynamic. The impacts of emerging policy are becoming clearer as various jurisdictions finalize and implement new regulations. The Canadian government has tabled a bill to legislate net zero emissions by 2050. This ambitious target is supported by the Healthy Environment and a Healthy Economy Plan, which targets a carbon price of $170 per tonne by 2030.

Husky operates in many jurisdictions that regulate or have proposed to regulate air pollutants, including GHG emissions. Air regulations include:

- absolute and intensity-based emissions limits or targets.
- market based frameworks.
- equipment and/or facility level emissions performance standards and reporting.
- other regulatory measures including low carbon fuel and renewable fuel standards.

Risks associated with climate change trends and regulations are discussed under "Risk Factors".

International Climate Change Agreements

Canada, Indonesia and China are all signatories to the Paris Agreement drafted at the United Nations Framework Convention on Climate Change Conference of the Parties held in Paris, France in December 2015.

Canada has submitted a Nationally Determined Contribution to reduce GHG emissions by 30% below 2005 levels by 2030. Indonesia has pledged a 29% reduction below a "business as usual" baseline by 2030. China announced that it will strengthen its 2030 climate target to see peak emissions before 2030, but with reductions per unit GDP by 60-65% from 2005 levels and aim to achieve carbon neutrality before 2060. There is a commitment to review and increase pledges every five years under the Paris Agreement.

In November 2018, China and Canada signed a memorandum of understanding on climate change cooperation.

On November 4, 2019, the U.S. issued formal notification of withdrawal from the Paris Agreement, to take effect on November 4, 2020. However, on January 20, 2021 President Biden issued an executive order starting the process for the U.S. to rejoin the Paris Agreement.

Canadian Federal Regulations

The Government of Canada has begun addressing emissions from specific sectors of the economy, including working closely with the U.S. government on North American vehicle emissions standards. Canada has adopted renewable fuels regulations, requiring fuel producers and importers to have an average of at least 5% of their gasoline supply come from renewable sources (such as ethanol) and to have an average of at least 2% of their diesel supply come from renewable sources (such as biodiesel).

In 2012, the Canadian Council of Ministers of the Environment agreed to implement a new Air Quality Management System ("**AQMS**") to protect human health and the environment through the continuous improvement of air quality in Canada. AQMS includes three main components: Canadian Ambient Air Quality Standards ("**CAAQS**"); Base-Level Industrial Emissions Requirements ("**BLIERs**"); and the management of air quality through local air zones and regional airsheds.

CAAQS are the AQMS driver and set the bar for air quality management across the country. New standards for ozone and fine particulate matter for 2015 and 2020 were published in 2013. New CAAQS for sulphur dioxide for 2020 and 2025 were announced in 2016, and new CAAQS for nitrogen dioxide for 2020 and 2025 were published in 2017.

Under the BLIERs, three regulations and a guideline were developed within the AQMS. The first of the *Multi-Sector Air Pollutants Regulations* was published in June 2016, which includes regulations applicable to reciprocating spark-ignited natural gas engines and non-utility boilers and heaters operating within the oil & gas sector. An emissions guideline under the *Environmental Protection Act* (Canada) for stationary gas turbines was published in November 2017. Other sectors and air pollutants are expected to be added to the regulations in the future.

The BLIERs pertaining to oxides of nitrogen ("**NOx**") emissions from boilers and heaters and NOx emissions from reciprocating engines in industrial facilities are applicable to Husky's Canadian upstream and downstream oil and gas facilities. The Boiler & Heater BLIER and Reciprocating Engine BLIER have introduced performance, design and monitoring standards for both existing and new equipment units, whereas the Stationary Gas Turbine BLIER has only introduced performance and design standards for new equipment.

In June 2018, the federally-enacted *Greenhouse Gas Pollution Pricing Act* came into force, under which the federal government seeks to implement its carbon-pricing plan outlined in the 2016 Pan-Canadian Framework on Clean Growth and Climate Change, including establishing a Canada-wide minimum price on carbon emissions through two key mechanisms: a carbon levy applied to fossil fuels ($20 per tonne of CO_2e starting on April 1, 2019 and increasing by $10 annually to $50 per tonne in 2022); and an output-based pricing system applicable to industrial facilities with GHG emissions above 50,000 tonnes of CO_2e per year with opt-in provisions for smaller facilities.

On July 10, 2019, the Government of Canada published the Output-Based Pricing System ("**OBPS**") Regulations under the *Greenhouse Gas Pollution Pricing Act*. The federal OBPS includes sectorial Output-Based Standards, provisions pertaining to GHG emissions quantification and reporting, as well as details on the administration process and content of verification reports. The federal OBPS is applicable to Husky's Minnedosa Ethanol Plant effective January 1, 2019.

A federal Clean Fuel Standard ("**CFS**") Discussion Paper was released in February 2017. The CFS will be developed to achieve 30 megatonnes of annual reductions in GHG emissions by 2030 through requiring reductions in fuel carbon intensities based on a life- cycle analysis and will go beyond transportation fuels to include fuels used in industry and buildings. In December 2017, the CFS regulatory framework was published, and in December 2018, the Government of Canada published the Regulatory Design Paper on the CFS. The CFS Regulatory Design Paper focuses on the liquid fuel stream regulations, and key design elements include a carbon intensity reduction of 10 g CO2/MJ (approximately 11%) by 2030 from a 2016 baseline. A Proposed Regulatory Approach was also released in June 2019 that builds on the previous papers issued by Environment Canada. For liquid fuels, including transportation fuels, draft regulations were published in late 2020 with final regulations in 2021 coming into force in 2022.

The Government of Canada is committed to reducing methane emissions from the oil and gas sector by 40% to 45% below 2012 levels by 2025. Final methane reduction regulations for the upstream oil and gas industry were published on April 26, 2018. Emissions sources subject to these regulations include venting from wells and batteries (including associated gas at oil facilities), storage tanks, pneumatic devices, well completions, compressors and fugitive equipment leaks. Final regulations apply to new and existing sources, with the first requirements coming into force in 2020, and the remaining requirements by 2023. Alberta and Saskatchewan methane regulations achieved equivalency to the federal regulations in November 2020.

The *Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Petroleum Sector)* pertaining to the downstream oil and gas industry were published by the Government of Canada in November 2020. The regulations require the implementation of comprehensive Leak Detection and Repair programs at refineries, upgraders and certain petrochemical facilities. These facilities are also required to monitor the levels of certain volatile organic compounds at facility perimeters. The regulations come into force effective January 1, 2022.

Canadian Provincial Greenhouse Gas Regulations

Under the *Greenhouse Gas Pollution Pricing Act* regime, the federal carbon pollution pricing system can be implemented in provinces and territories that do not have a carbon pollution pricing system that meets the federal benchmark or that request it. Provinces and territories had until September 1, 2018, to outline their plans.

There remains uncertainty with respect to the extent of the Government of Canada's jurisdiction to set minimum standards applicable to the provinces. On September 22 and 23, 2020, the Supreme Court of Canada heard appeals in relation to constitutional challenges of the validity of the federally-enacted *Greenhouse Gas Pollution Pricing Act*, but has yet to issue its decision.

In Alberta, the *Emissions Management and Climate Resilience Act* addresses carbon dioxide, methane and other specified GHG emissions. The Act establishes the framework and regulation-making authority for the governance of specified gas emissions and mandates reporting requirements for GHG emitters in Alberta.

Alberta's provincial OBPS scheme under the *Technology Innovation and Emissions Reduction Regulation* ("**TIER**") and the emissions sources it covers was confirmed to meet equivalency with the federal minimum standards on December 6, 2019. The federal fuel charge applies in Alberta where TIER does not apply. The TIER, effective January 1, 2020, regulates facilities in Alberta emitting over 100,000 tonnes CO_2e/year with an opt-in program for smaller emitters and for conventional oil and gas aggregate facilities. TIER allows for the option of a facility specific performance baseline or a sector specific best performance standard as the basis for reduction. The conventional oil and gas aggregated facility opt-in to TIER provides significant emissions intensive, trade exposed ("**EITE**") protection for the sector as participation in the large emitters' regulation exempts the facilities from the Federal Fuel Levy. Alberta's TIER regulation is expected to lessen the financial burden associated with carbon compliance by allowing companies to improve emissions based on historical facility performance rather than being subject to sector intensity benchmarks that are typically set by the largest, most mature operations. Alberta is expected to follow federal pricing of \$30/tonne CO_2e in 2020 escalating to \$50/tonne CO_2e by 2022.

Alberta's methane regulations, effective January 1, 2020 limit methane emissions at a site and equipment level at upstream oil and gas facilities, and focus on measurement, monitoring and reporting on methane emissions, including fugitive emissions. This regulatory framework is intended to achieve Alberta's methane emissions reduction target of 45% by 2025 and equivalency with the Government of Canada's methane reduction goals.

In December 2017, the Government of Saskatchewan released "Prairie Resilience: A Made-In-Saskatchewan Climate Change Strategy" that includes the implementation of sector-specific output-based performance standards on facilities emitting more than 25,000 tonnes of CO_2e per year. *The Management and Reduction of Greenhouse Gases Amendment Act* ("**MRGHG**"), and various GHG regulations under the Act impose a carbon price (starting at \$20 per tonne of CO_2e in 2019 escalating by \$10/year up to \$50/tonne in 2022) on facilities that emit more than 25,000 tonnes of CO_2e/year. Facilities such as the Upgrader, and Husky's ethanol plant and Saskatchewan thermal projects are subject to MRGHG. The Province of Saskatchewan has a carbon tax that applies to all fuel for all facilities under that threshold. As part of the its October 23, 2018 announcement on climate policy equivalency, the Government of Canada announced the federal OBPS would be applicable to Saskatchewan's electricity generation and natural gas transmission lines as of January 1, 2019. The federal fuel charge has also taken effect in Saskatchewan as of April 2019. Saskatchewan has published the Management and Reduction of Greenhouse Gases (Upstream and Gas Aggregate Facility) Standard and is allowing opt-in of the conventional oil and gas assets to provide EITE protection for the sector, as participation in the large emitters' regulation exempts the facilities from the Federal Fuel Levy.

The Government of Saskatchewan published the *Oil and Gas Emissions Management Regulations* on December 14, 2018, effective January 1, 2019, which apply to oil and gas operations with aggregated emissions exceeding 50,000 tonnes of CO_2e per year. These regulations seek to reduce methane emissions from the oil and gas sector by setting target emissions intensities for various regions within the province. The regulations are intended to reduce provincial methane emissions intensity by 45% by 2025.

On October 3, 2018, Manitoba announced it was canceling its carbon tax. As part of the October 23, 2018 announcement by the federal government, the federal carbon policy applies in full in Manitoba including the application of an output-based standard to Husky's Minnedosa ethanol plant.

On June 7, 2016 the *Management of Greenhouse Gas Act* passed in the House of Assembly of NL, establishing the legislative basis for a provincial industrial large emitters program and reporting regulations. The *Management of Greenhouse Gas Reporting Regulations* came into force on March 7, 2017. The Government of Newfoundland and Labrador, in consultation with industry, has developed and proposed GHG regulations for the offshore petroleum production sector to be incorporated by amendment to the *Management of Greenhouse Gas Act* and the Atlantic Accord. On October 23, 2018 the Government of Canada deemed the NL large emitter and fuel levy programs to price carbon as equivalent to federal standards. Subsequently, *Budget Implementation Act, 2018, No. 2* ("Bill C-86"), was entered into the House of Commons on October 29, 2018 to amend the Atlantic Accord to enable the C-NLOPB to manage the requirements of the provincial GHG reporting regulations in the offshore petroleum sector.

The NL performance-based regulation imposes carbon pricing (beginning at \$20/tonne in 2019 and escalating to \$50/tonne in 2022) on petroleum production facilities with GHG emissions exceeding 25,000 tonnes/year. Beginning January 1, 2019, a levy of 4.42 cents per litre on gasoline and 5.37 cents per litre on diesel (both equivalent to \$20/tonne) will be applied as part of the carbon tax. This provincial Gasoline and Diesel Tax will be adjusted with a goal of protecting economic competitiveness related to taxation (including carbon tax) of fuel products. The provincial carbon tax rates will only increase to match equivalent increases in carbon taxation programs in neighboring Atlantic provinces. There are noted exemptions for exploration drilling and aviation fuels. However, the addition of this carbon tax to marine diesel will increase operating costs for Atlantic region operations.

U.S. Greenhouse Gas Regulations

The U.S. does not have federal legislation establishing targets for the reduction of, or limits on, GHG emissions. However, the federal Environmental Protection Agency ("**EPA**") has and may continue to promulgate regulations concerning the reporting and control of GHG emissions. Since 2010, the EPA's Greenhouse Gas Reporting Program ("**GHGRP**") requires any facility releasing more than 25,000 tonnes of CO_2e emissions per year to report those emissions on an annual basis. In addition to reporting direct CO_2e emissions, the GHGRP requires refineries to estimate the CO_2e emissions from the potential subsequent combustion of the refinery's products.

In May 2010, the EPA finalized the Greenhouse Gas Tailoring Rule. This rule updated the *Clean Air Act* (USA) by phasing in permitting requirements for GHG emissions, including Best Available Control Technology ("**BACT**") requirements for new and modified sources of air emissions emitting more than a threshold quantity of GHG. In June 2014, the U.S. Supreme Court invalidated portions of the Greenhouse Gas Tailoring Rule but upheld the EPA's authority to require BACT for GHG emissions associated with sources that must obtain Prevention of Significant Deterioration permits based on their non-GHG emissions.

U.S. Renewable Fuel Standard

The U.S. created its Renewable Fuel Standard ("**RFS**") program with the stated intention of reducing GHG emissions and expanding the renewable fuels sector, while reducing U.S. reliance on imported oil. The RFS program was authorized under the *Energy Policy Act* (USA) of 2005 and expanded under the *Energy Independence and Security Act* (USA) of 2007. The EPA implements the RFS program in consultation with the U.S. Department of Agriculture and Department of Energy.

The RFS program is a national policy that requires a certain volume of renewable fuel to replace or reduce the quantity of petroleum-based transportation fuel. Obligated parties under the RFS program are refiners or importers of gasoline or diesel fuel. Compliance is achieved by blending renewable fuels into transportation fuels or by obtaining credits, called Renewable Identification Numbers ("**RINs**") to meet an EPA-specified Renewable Volume Obligation ("**RVO**"). The RFS program, through the EPA-specified RVOs, requires refiners to add annually increasing amounts of renewable fuels to their petroleum products or to purchase RINS in lieu of such blending.

The EPA calculates and establishes RVOs every year through rulemaking. The standards are converted into a percentage, and obligated parties must demonstrate compliance annually.

Husky's GHG Policies and Outlook

As part of long-range planning, Husky has assessed future compliance costs associated with regulations of GHG emissions in its operations and the evaluation of future projects, based on Husky's outlook for carbon pricing under current and pending regulations. The impact of recently announced regulations in Canada has been evaluated as provinces and the federal government finalize carbon pricing regulations. Husky has monitored international and domestic efforts to address climate change, including international low carbon fuel standards and regulations and other emerging regulations in the jurisdictions in which Husky operates.

In 2020, Husky set and published a GHG Scope 1 emissions reduction target of 25% of 2015 emissions intensity by 2025, and an aspirational goal of net zero emissions by 2050. Performance against the 2025 greenhouse gas emissions intensity reduction target has been linked to executive pay. Asset-level carbon management plans have been prepared to ensure that climate change and emissions reductions have been at the forefront of business decisions. In 2019, Husky's gross GHG Scope 1 emissions were 9,570,000 tonnes CO_2e. GHG Scope 2 emissions in 2019 were 1,915,000 tonnes CO_2e.

Concurrent with the announcement of the Cenovus Transaction, Cenovus stated that the combined company will maintain the ambition established independently by Cenovus and Husky of achieving net zero emissions by 2050, and that the combined company will remain committed to pursuing ESG targets and will undertake a thorough analysis before setting meaningful targets for the new portfolio.

By estimating its current and projected future emissions and understanding forthcoming regulations that may impact its business, Husky has determined the areas of its operations that may face future compliance obligations or additional costs from regulation. In 2020 Husky conducted its Paris Accord 2-degree scenario analysis to test its resilience against the financial risks associated with emerging climate policies and commodity pricing in a carbon-constrained economy. Husky's Enterprise Risk Management Framework has supported decision making via comprehensive and systematic identification and assessment of risks that could materially impact Husky's results.

Husky's GHG management framework has included a process for climate-related technology assessment, including new innovations that can reduce emissions intensity, and innovations that could have disrupted Husky's business strategy. As new technologies have been identified by subject matter experts across Husky, they are shared through Husky's Air Critical Competency Network and as appropriate, are incorporated into regular updates to EHSEC, the ESG Steering Committee and business unit leadership. Husky employs a Marginal Abatement Cost Curve tool as part of a process to review technologies that might qualify for external funding and enhance business cases for technology risk mitigation.

Husky recognizes the recommendations of the Financial Stability Board's Task Force on Climate-related Financial Disclosures ("**TCFD**"). Husky voluntarily has responded annually to the Climate Disclosure Project ("**CDP**") climate change questionnaire, which as of 2018 had fully adopted the TCFD recommendations.

Environmental Protection

General

Oil and conventional natural gas operations are subject to environmental regulations pursuant to a variety of federal, provincial, state and local laws and regulations, as well as international conventions (collectively, **"environmental regulations"**).

Environmental regulations, policies and legal agreements regulate and impose restrictions, liabilities and obligations on how industry is required to handle, store, transport, treat and dispose of emissions, water/waste water, hazardous substances and wastes. Controls and limits on spills, releases and emissions to the environment, including GHG emissions (as discussed in greater detail above) are required to be diligently managed. Environmental regulations also require that wells and facilities be constructed, operated, maintained, abandoned and reclaimed in compliance with pertinent regulatory requirements. In addition, certain types of operations, including exploration and development projects and significant changes to certain existing projects, may require the submission and approval of environmental impact assessments.

Some examples of potential new or enhanced environmental regulations, and impacts of possible changes, include:

- conventional air pollutant and GHG emissions regulations and mandatory reductions.
- calculation and regulation of carbon intensity of fuels, including transportation fuels.
- potential for restrictive operating policies on development in areas of value to species at risk.
- increased restrictions on freshwater licensing.
- increased restrictions on activities in fish-bearing water courses.
- enhanced groundwater and surface water monitoring.
- enhanced water discharge criteria.
- increased restrictions on waste water disposal.
- enhanced water recycle criteria.
- enhanced water crossing monitoring and reporting requirements.
- enhanced requirements for environmental assessment, including the potential for more projects to require assessments, longer review times, additional information requirements and increased requirements related to Indigenous consultation.
- water management for hydraulic fracturing.
- wetland compensation.
- induced seismicity.
- feedstock and product transportation by rail, pipeline and roadway.
- pipeline integrity management.
- remediation regulation.
- reclamation criteria.
- increased financial security requirements for abandonment, remediation, and reclamation.
- constraints mapping, footprint reduction and land use.
- measurement requirements for oil and gas operations.
- investigations of operational upsets that result in emissions.

Bill C-69

In Canada, Bill C-69, *An Act to enact the Impact Assessment Act and the Canadian Energy Regulator Act, to amend the Navigation Protection Act and to make consequential amendments to other Acts*, (2019), was passed by Parliament on June 21, 2019. The *Impact Assessment Act*, the *Canadian Energy Regulator Act*, the *Canadian Navigable Waters Act*, and associated regulations came into force on August 28, 2019. Of note, the *Impact Assessment Act* creates the new Impact Assessment Agency of Canada, repeals the *Canadian Environmental Assessment Act, 2012*, and provides a new approach to the federal assessment of major projects in Canada. The *Canadian Energy Regulator Act* replaces the National Energy Board with the Canada Energy Regulator ("**CER**") and defines its composition, mandate and powers. The role of the CER is to regulate the exploitation, development and transportation of energy within Parliament's jurisdiction.

The *Canadian Navigable Waters Act* increases protections of navigable waters, expanding the regulation of major works and obstructions, and setting requirements for minor works on all navigable waters.

Bill C-68, *An Act to amend the Fisheries Act and other Acts in consequence,* (2019), was also passed in parliament on June 21, 2019 and outlined amendments to the *Fisheries Act* which came into effect on August 28, 2019. The fish and fish habitat protection provisions under this Act strengthen some protections for aquatic species and protect the interests of people who depend on them, particularly Indigenous communities.

Transport Canada

Effective August 3, 2020, new Transport Canada regulations, titled *Transportation of Dangerous Goods by Rail Security Regulations*, require security plans and security training to be established for TDG by rail. Specific requirements are based on quantity and type of dangerous goods transported by rail. The new security regulations will affect sites which load prior to, or unload following, rail transportation, or offer for transport dangerous goods by rail in quantities outlined in the regulations.

Husky's Operations

Husky's operations are subject to various environmental requirements under federal, provincial, state and local laws and regulations, as well as international conventions. These laws and multiple regulatory requirements cover matters such as: control of air emissions, management and recycling of wastewater, non-saline water use, protection of surface water and groundwater, land disturbances and handling and disposal of waste materials. These regulatory requirements have grown in number and complexity over time, covering a broader scope of industry operations and products. Husky has been actively engaged with federal, state, provincial, local agencies and through industry associations to develop sustainable regulations that allow for compliant operations and are also protective of the environment. In addition to existing requirements, Husky recognizes that there are emerging regulatory frameworks that have a potential financial impact on Husky's operations. As part of Husky's review of proposed regulations that may affect its business and operations, Husky may, from time to time, audit and prepare an internal analysis of the possible or expected impact of new regulations, which are subject to various uncertainties. See "Risk Factors."

Husky minimizes impact on the landscape through consideration and application of the mitigation hierarchy, with the implementation of avoidance and mitigation programs where appropriate. Monitoring the effectiveness of mitigation occurs where mandated by regulatory requirements or stakeholder commitments and may occur when Husky recognizes the value, such as for complex projects or learning opportunities. Where monitoring indicates that corrective action is warranted, Husky's policy has been to take an adaptive proactive management approach.

Water

Numerous regulations are imposed on the oil and gas industry's operations with the general goal of ensuring surface water and fresh groundwater resources are protected. Guidelines cover the following:

- oil and gas well, pipeline and facility offsets from fresh surface water courses and domestic water wells.
- drilling fluids, well construction materials and methods to isolate fresh groundwater aquifers from resource exploration, extraction and disposal activities.
- downhole offsets for completions operations, ensuring isolation from fresh groundwater aquifers, with specific risk mitigation expectations for hydraulic fracturing.
- monitoring of fresh groundwater aquifers and wetlands at major operating facilities.
- monitoring of assets that cross fish bearing streams ensuring passage is unrestricted.
- water discharge criteria for onshore and offshore facilities.
- fluid transport, handling and storage.
- process water recycling targets.

Water withdrawals are regulated in Husky's operating jurisdictions with the goal of minimizing impacts to freshwater resources. Oil and gas companies have reporting requirements relating to most licenced freshwater withdrawals. Policies dictate water source selection and management. Water withdrawals are further governed by local watershed and/or industry water management plans.

Husky has a corporate Water Standard that mandates Water Risk Assessments and Water Management Plans for its facilities, which include consideration of regulatory risks. The purpose of these Water Risk Assessments is to try to identify and mitigate these risks. Water Risk Assessments consider both known proposed water regulations and possible future regulations (not currently proposed). Husky voluntarily responded annually to the CDP water questionnaire.

Monitoring of surface water and ground water quality relating to hydraulic fracturing operations is not regulated in the jurisdictions in which Husky has these operations. Husky has proactively implemented a recommended practice for completing baseline quality and quantity tests for water wells located in proximity to its hydraulic fracturing operations.

As an active member of the In-situ Water Technology Development Centre and Canada's Oil Sands Innovation Alliance ("**COSIA**") Water Committees, Husky has been involved in developing new technologies to recycle wastewater, reduce water use and improve energy efficiency. Husky has had teams dedicated to solving water management challenges by leveraging expertise in hydrogeology, surface water aquatics, hydrology, water treatment and drilling waste management. Husky continues to pursue opportunities to conserve water, through alternative water sources and recycling of produced water. At the Tucker Thermal

Project, produced water is recycled and make-up water is sourced from saline, non-potable groundwater. The Sunrise Energy Project recycles produced water and supplements this with process-affected water from a nearby oil sands operation after it has been treated, and lower quality non-saline groundwater that is in contact with bitumen to generate steam for oil recovery. The Lima Refinery has a wastewater reuse program that substantially reduces its water needs annually. As a specific action related to water supply risk in its operations, Husky is participating in a research project to understand potential climate impacts to industrial water supplies on the North Saskatchewan River. This multi-year study is a collaborative project with academia and another industry partner.

Migratory Birds and Species at Risk

Canada's oil and gas industry may affect migratory birds and bird habitat as well as habitat impacting sensitive species through land disturbance activities and operating practices (e.g., sludge ponds, vegetation clearing). Industry activities risk contravening the *Migratory Bird Convention Act* (Canada) ("**MBCA**") or the *Species at Risk Act* (Canada) ("**SARA**") and supporting legislation that prohibits the disturbance and destruction of migratory birds, their eggs and/or their nests and mandates the protection and management of sensitive species habitat. There are maximum fines of up to $6 million, with all subsequent fines doubling, for corporations that are convicted under the MBCA. For corporations, current penalties under SARA include fines of $1 million, with potential to double based on subsequent contraventions. U.S. operations are subject to similar requirements pursuant to the *Migratory Bird Treaty Act and the Endangered Species Act* (USA).

In October 2020, Alberta Environment and Parks and Environment and Climate Change Canada signed an agreement for the conservation and recovery of the threatened woodland caribou in Alberta, under section 11 of the *Species at Risk Act*. The purpose of the agreement is to support the conservation and recovery of woodland caribou to naturally self-sustaining status by outlining measures to be taken by the parties. Industry and government activities in caribou ranges in Alberta must align with the principles of this agreement to avoid enactment of a federal Environmental Protection Compliance Order in the province.

Husky has improved the protection of migratory birds through development of a Standard for Pre-Construction Migratory Bird Incidental Take Mitigation, as well as the preparation of a Bird Deterrent Guidance document to assist environmental staff and operators in the awareness and selection of the most appropriate deterrent systems for each facility. For Atlantic operations, in accordance with Husky's permit from the Canadian Wildlife Service ("**CWS**"), Husky's Seabird Handling Procedure provides guidance to personnel on how to handle birds that arrive on an installation. Oiled birds are cleaned and rehabilitated at Husky's Seabird Recovery Centre in consultation with CWS. Husky has improved protection of species at risk and their habitats by conducting environmental surveys and wildlife sweeps when appropriate to identify sensitive habitats, individuals and wildlife features (dens, for example) to allow implementation of appropriate mitigation measures. Husky representation at industry associations such as the Canadian Association of Petroleum Producers ("**CAPP**"), the Petroleum Technology Alliance Canada and COSIA which Husky joined in 2020, has allowed Husky to collaborate with other environmental professionals to discuss innovative ideas and participate in multi-stakeholder discussions. The associations work towards common goals such as developing industry-wide solutions to reduce risk of impacts to migratory birds and SARs.

Ice Management

Husky has several policies in place to protect people, equipment and the environment in the event of extreme weather conditions and adverse ice conditions. Husky has developed Adverse Weather Guidelines for the *SeaRose* FPSO and is managing physical risk through engineering for 1:100-year weather events.

Husky's Atlantic operations have a robust ice management program, which uses a range of resources including an industry shared ice surveillance aircraft, as well as synergistic relationships with government agencies including Environment and Climate Change Canada, the Coast Guard and Canadian Ice Service. Regular ice surveillance flights commenced in February 2020 and continue until the risk has abated. In addition, Atlantic operators employ a series of supply and support vessels to actively manage ice and icebergs. These vessels are equipped with a variety of ice management tools including towing ropes, towing nets and water cannons. Husky also maintains a series of ad-hoc relationships with contractors, allowing the quick mobilization of additional resources as required.

Husky regularly assesses all aspects of its ice management program to ensure that the program continues to evolve as more information about the characteristics of ice and icebergs in the Atlantic becomes available and as new technologies are developed. Husky continues to look at ways to improve its ability to predict and respond to sea ice and icebergs with ongoing research and development. Recent initiatives include the design and fabrication of modular, heavy weather nets with sensors and development of a Common Operating Picture on Husky's contracted geographic information systems software module including ice flight information, location, drift models, and pack ice drift model runs. Husky now has a dedicated ice management room onshore, which mirrors the offshore and allows for real-time monitoring of field operations. Additional research and development activity related to ice management is continuing.

Abandonment, Reclamation and Remediation

Ongoing remediation and reclamation work is occurring at approximately 3,700 well sites and facilities in Western Canada. During 2020, Husky spent approximately $39 million on asset retirement obligations ("**ARO**") in North America. Husky expects to spend approximately $71 million in 2021 on ARO and environmental site closure activities in North America, including abandonment, decommissioning, reclamation and remediation.

Husky has also pioneered a program-based approach to asset retirement whereby all retirement activities are undertaken as a single program, greatly increasing the efficiency and effectiveness of the work. The Alberta Energy Regulator has embraced Husky's approach, now referred to as "Area-Based Closure", has used it as a template for all of industry to adopt where possible and has incorporated it into its closure regulations.

In Asia Pacific and in accordance with the provisions of the regulations of the People's Republic of China, Husky has deposited funds into separate accounts restricted to the funding of future ARO. As at December 31, 2020, Husky had deposited funds of $164 million, which were classified as non-current liabilities.

Husky completed a review of its ARO provisions, including estimated costs and projected timing of performing the abandonment and retirement operations. The results of this review have been incorporated into the estimated liability as disclosed in Note 18 of Husky's audited consolidated financial statements as at and for the year ended December 31, 2020.

Husky has an ongoing environmental monitoring program at owned and leased retail locations and performs remediation where required. Husky also has ongoing monitoring programs at its downstream facilities, including refineries and the Upgrader. Husky has several inactive facilities ranging from former refineries to retail locations. Management and remediation plans are prepared for these sites based on current and future land use.

RISK FACTORS

The following summarizes what the Company believes to be the most significant risks relating to its operations which should be considered when purchasing securities of the Company. The Company has developed an enterprise risk matrix to identify risks to its people, the environment, its assets and its reputation, and to systematically mitigate these risks to an acceptable level. The risk matrix and associated mitigation strategies are reviewed quarterly by senior management and the Audit Committee, and annually by the Board.

Operational and Safety Incidents

The Company's businesses are subject to inherent operational risks which have the potential to impact safety, the environment, its assets and its reputation. In general, the Company's operations are subject to operational risks, including, but not limited to: fires, loss of containment, blowouts, power outages, freeze-ups and other similar events; oil and natural gas leaks; encountering unexpected formations or pressures; premature declines of reservoir pressure or productivity; uncontrollable flows of oil, natural gas and well fluids; spills at truck terminals and hubs; spills associated with the loading and unloading of potentially harmful substances onto trucks; release of tailings or harmful substances into a water system; the breakdown or failure of equipment, pipelines and facilities, information systems and processes; the performance of equipment at levels below those originally intended (whether due to misuse, unexpected degradation or design, construction or manufacturing defects); releases or spills from shipping vessels; failure to maintain adequate supplies of spare parts; the compromise of information technology and control systems and related data; operator error; labour disputes; disputes with interconnected facilities and carriers; operational disruptions or apportionment on third-party systems or refineries, which may prevent the full utilization of the company's facilities and pipelines; epidemics or pandemics; and catastrophic events, including, but not limited to, war, extreme weather events, natural disasters, explosions, acts of sabotage and other similar events.

Failure to manage the hazards and associated risks effectively could result in potential fatalities, environmental impacts, interruptions to activities or use of assets, or loss of license to operate. The Company implements an Operational Integrity Management System designed to systematically identify, assess and manage operational and safety risks to tolerable levels. In addition, the Company, in accordance with industry practice, maintains insurance coverage against losses from certain of these risks. Nonetheless, insurance proceeds may not be sufficient to cover all losses, and insurance coverage may not be available for all types of operational risks.

Commodity Price Volatility

The Company's results of operations and financial condition are dependent on the prices received for its refined products, crude oil, NGL and conventional natural gas production. Lower prices for crude oil, NGL and conventional natural gas could adversely affect the value and quantity of the Company's oil and gas reserves. The Company's reserves include significant quantities of heavier grades of crude oil that often trade at a discount to light crude oil. Heavier grades of crude oil are typically more expensive to produce, process, transport and refine into high-value refined products. Refining and transportation capacity for various grades of crude oil may be constrained from time to time, creating the need for additional refining and transportation capacity. Wider price differentials between heavier and lighter grades of crude oil could have a material adverse effect on the Company's results of operations and financial condition, reduce the value and quantities of the Company's heavier crude oil reserves and delay or cancel projects that involve the development of heavier crude oil resources. There is no guarantee that pipeline development projects or other transportation alternatives will provide sufficient transportation capacity and access to refining capacity to accommodate expected increases in North American heavy crude oil and bitumen production.

Prices for refined products and crude oil are based on world supply and demand. Supply and demand can be affected by several factors including, but not limited to, actions taken by OPEC, non-OPEC crude oil supply, social conditions in oil producing countries, the occurrence of natural disasters, general and specific economic conditions, technological developments, prevailing weather patterns, government regulation and policies and the availability of alternate sources of energy.

The Company's conventional natural gas production is currently located in Western Canada and Asia Pacific. Western Canada's conventional natural gas production is subject to North American market forces. North American natural gas supply and demand is affected by several factors including, but not limited to, the amount of conventional natural gas available to specific market areas either from the wellhead of existing or accessible conventional or unconventional sources (such as from shale) or from storage facilities, technological developments, prevailing weather patterns, the U.S. and Canadian economies, the occurrence of natural disasters and pipeline restrictions. The price received by the Company for production from Asia Pacific is determined by long-term contracts.

In certain instances, the Company will use derivative instruments to manage exposure to price volatility on a portion of its refined product, oil and gas production, inventory or volumes in long-distance transit. The Company may also use firm commitments for the purchase or sale of crude oil and conventional natural gas.

The fluctuations in refined products, crude oil and conventional natural gas prices are beyond the Company's control and could have a material adverse effect on the Company's results of operations and financial condition.

Commodity Price Risk

In certain instances, the Company uses derivative commodity instruments and futures contracts on commodity exchanges, including commodity put and call options under a short-term hedging program, to manage exposure to price volatility on a portion of its refined product, oil and gas production, and inventory or volumes in long distance transit. The Company may also use firm commitments for the purchase or sale of crude oil and conventional natural gas.

The Company's results will be impacted by a decrease in the price of crude oil and conventional natural gas inventory. The Company has crude oil inventories that are feedstock, held at terminals or part of the in-process inventories at its refineries and at offshore sites. Due to the integrated nature, the Company has a natural partial mitigation to the WCS differential risk. The Company also has conventional natural gas inventory that could have an impact on earnings based on changes in conventional natural gas prices. All these inventories are subject to a lower of cost or net realizable value test on a quarterly basis.

Reservoir Performance and Reserves Estimate Risk

Lower than projected reservoir performance on the Company's key growth projects could have a material adverse effect on the Company's results of operations, financial condition, business strategy and reserves. Inaccurate appraisal of large project reservoirs could result in missed production, revenue and earnings targets and negatively affect the Company's reputation and investor confidence.

In order to maintain the Company's future production of crude oil, conventional natural gas and NGL and maintain the value of the reserves portfolio, additional reserves must be added through discoveries, extensions, improved recovery, performance related revisions and acquisitions. The production rate of oil and gas properties tends to decline as reserves are depleted while the associated unit operating costs increase. Maintaining an inventory of projects that can be developed depends upon, but is not limited to, obtaining and renewing rights to explore, develop and produce oil and natural gas, drilling success, completion of long lead time capital intensive projects on budget and on schedule and the application of successful exploitation techniques on mature properties.

The reserves data contained or referenced in this AIF represent estimates only. The accurate assessment of oil and gas reserves is critical to the continuous and effective management of the Company's upstream assets. Reserves estimates support various investment decisions about the development and management of oil and gas properties. In general, estimates of economically recoverable crude oil and conventional natural gas reserves and the future net cash flow therefrom are based upon a number of variable factors and assumptions, such as product prices, future operating and capital costs, historical production from the properties and the effects of regulation by government agencies, including with respect to royalty payments, all of which may vary considerably from actual results. The Company uses all available information at the effective date of the evaluation and internal qualified reserves evaluators to prepare the reserves estimates. As required by NI 51-101, the Company obtains the opinion of an independent reserves auditor on the Company's reserves. The audit covers more than 75% of the future net revenue discounted at 10% attributable to proved plus probable reserves with the remainder reviewed by the independent qualified reserves auditor. However, given the best technical information and evaluation techniques, all such estimates are still to some degree uncertain. All reserves estimates involve a degree of ambiguity and, at times, rely on indirect measurement techniques to estimate the size and recoverability of the resource. While new technologies have increased the accuracy of these techniques, there remains the potential for human or systemic error in recording and reporting the magnitude of the Company's oil and gas reserves. Estimates of the economically recoverable oil and gas reserves attributable to any particular property or group of properties, and estimates of future net revenues expected therefrom, may differ substantially from actual results even though the total company reserves are shown to be reliable through the historical total company technical reserves revisions. The Company has a diverse portfolio of assets by product type, reservoir type and location which is a factor in mitigating specific property risks.

Restricted Market Access and Pipeline Interruptions

The Company's results of operations and financial condition depend upon the Company's ability to deliver products to the most attractive markets. The Company's results of operations could be materially adversely affected by restricted market access resulting from a lack of pipeline or other transportation alternatives to attractive markets as well as regulatory and/or other marketplace barriers. Interruptions and restrictions may be caused by the inability of a pipeline to operate, or they can be related to capacity constraints as the supply of feedstock into the system exceeds the infrastructure capacity. If oil production across North America experiences growth, the availability of infrastructure to carry the Company's products to the marketplace may be restricted in the next few years. Restricted market access may potentially have a material adverse effect on the Company's results of operations, financial condition and business strategy. Unplanned shutdowns and closures of its refineries or Upgrader may limit the Company's ability to deliver product with a material adverse effect on sales and results of operations.

Aviation Incidents

The Company's Offshore operations in Canada and China rely on regular travel by helicopter. A helicopter incident resulting in loss of life, facility shutdown or regulatory action could have a material adverse effect on the operations of the Company. This risk is managed through an aviation management process. Aviation Safety Reviews are conducted by third party specialist contractors to verify that helicopter service providers meet the Company's and industry standards with respect to aviation safety. The reviews include evaluation of aircraft type, effectiveness of the safety and maintenance management systems and competency and training programs for critical roles in the operation of helicopters. Helicopters chartered to support Husky Offshore operations must be fit for service and as such are fitted with multiple redundant systems to address a wide range of potential in-flight emergencies. Additional measures specific to the Company's challenging operating environments are specified in the Company's design requirements including anti- icing and floatation systems effective for the maximum allowable sea height operating limits. Pilots are trained to address potential emergency situations through regular real-time and simulator training aligned with industry best practice.

Security and Terrorist Threats

Security threats and terrorist or activist activities may impact the Company's personnel, which could result in injury, death, extortion, hostage situations and/or kidnapping, including unlawful confinement. A security threat, terrorist attack or extremist incident targeted at a facility, office or offshore vessel/installation owned or operated by the Company could result in the interruption or cessation of key elements of the Company's operations. Outcomes of such incidents could have a material adverse effect on the Company's results of operations, financial condition and business strategy. The risk to employees and board members due to ongoing social unrest in Hong Kong is being managed through reduced travel and increased awareness and monitoring of the situation. The potential for detention and/ or incarceration of the Company's employees/contractors entering or working in China remains, and as a result, review and reconsideration for travel into China has become a business/corporate process.

The Company does not own proved or probable reserves in or near areas of armed conflict. According to the Uppsala Conflict Data Program, armed conflict is defined as "contested incompatibility that concerns government and/or territory over which the use of armed force between the military forces of two parties, of which at least one is the government of a state, has resulted in at least 25 battle-related deaths each year."

Skilled Workforce Attraction and Retention

Successful execution of the Company's strategy is dependent on ensuring the Company's workforce possesses the appropriate skill level. Failure to attract and retain personnel with the required skill levels could have a material adverse effect on the Company's financial condition and results of operations.

Partner Misalignment

Joint venture partners operate or jointly control a portion of the Company's assets in which the Company has an ownership interest. This can reduce the Company's control and ability to manage risks. The Company is at times dependent upon its partners for the successful execution of various projects. If a dispute with partners were to occur over the development and operation of a project or if partners were unable to fund their contractual share of the capital expenditures, a project could be delayed and the Company could be partially or totally liable for its partner's share of the project.

Major Project Execution

The Company manages a variety of oil and gas projects ranging from upstream to downstream assets across its global portfolio. The wide range of risks associated with project development and execution, as well as the commissioning and integration of new facilities with existing assets, can impact the economic viability of the Company's projects. Project risks may result in extended stakeholder consultation, additional environmental assessments and public hearings which may delay necessary environmental and regulatory approvals. Project risks may also manifest through schedule delays, cost overruns and commodity price drops. Some risks can impact the Company's safety and environmental records thereby negatively affecting the Company's reputation and social license to operate.

Government Regulation

Given the scope and complexity of the Company's operations, the Company is subject to regulations and interventions by governments at the federal, provincial, state and municipal levels in the countries in which it conducts its operations, or development or exploratory activities. As these governments continually balance the needs of the community for economic growth with Indigenous interests and stakeholders, the Company recognizes that the magnitude of regulatory risks has the potential to change over time. Changes in government policy, legislation or regulations could impact the Company's existing and planned projects as well as impose costs of compliance and increase capital expenditures and operating expenses. Examples of the Company's regulatory risks include, but are not limited to, uncertain or negative interactions with governments, uncertain energy policies, uncertain climate policies, uncertain environmental and safety policies, penalties, taxes, royalties, government fees, reserves access, limitations or increases in costs relating to the exportation of commodities, production restrictions, restrictions on the acquisition of exploration and production rights and land tenure, expropriation or cancellation of contract rights, limitations on control over the development and abandonment of fields and loss of licences to operate.

Environmental Risks

Changes in environmental regulations could have a material adverse effect on the Company's results of operations, financial condition and business strategy by requiring increased capital expenditures and operating costs or by impacting the quality of, formulation of or demand for the Company's products, which may or may not be offset through market pricing.

The Company anticipates that further changes in environmental legislation could occur, which may result in stricter standards and enforcement, larger fines and liabilities, the introduction of emissions limits, increased compliance costs and approval delays for critical licences and permits. Public and investment community interest in ESG issues has also increased significantly in recent years, as evidenced by the large number of signatories to the United Nations Principles for Responsible Investment.

It is not possible to accurately forecast the amount of additional investment in new or existing facilities required in the future for environmental protection or to address all new regulatory compliance requirements, such as reporting. See "Environmental, Social and Governance Considerations - Environmental Protection".

Climate Change Risks

Regulatory

Climate change regulations may become more onerous over time as governments implement policies to further reduce GHG emissions. As these regulations continue to evolve, they could have a material adverse effect on the Company's competitiveness, financial condition and results of operations through increased capital and operating costs and change in demand for refined products such as transportation fuels. Costs associated with levy payments for emerging climate change regulations may be significant. In December 2020, the Government of Canada released a new carbon tax pricing schedule with annual increases of \$15/tonne CO_2e per year beginning in 2023 (previously \$10/tonne CO_2e annual increase) resulting in pricing of \$65/tonne CO_2e for 2023 increasing to \$170/tonne in 2030.

In December 2018, the Government of Canada published the Regulatory Design Paper on the CFS that focuses on the liquid fuel stream regulations. The final regulations for liquid fuels are planned for early 2021, with the regulations expected to come into force in 2022. In December 2020, the Canadian government announced it would not be going forward with legislation on the gaseous and solids streams of the CFS.

The Company's U.S. Refining business could be exposed to increased costs related to U.S. federal GHG legislation/regulation that applies to the oil and gas industry, or consumption of petroleum products, or other legislation/regulation at the state or local level. Such legislation or regulations could require the Company's U.S. Refining operations to significantly reduce emissions and/or purchase emissions credits, thereby increasing operating and capital costs, and could change the demand for refined products which may have a material adverse effect on the Company's financial condition.

The Company complies with the RFS program in the U.S. by blending renewable fuels manufactured by third parties and by purchasing RINs on the open market. Due to regulatory uncertainty and in part due to the U.S. fuel supply reaching the "blend wall" (the 10% limit prescribed by most automobile warranties), the price and availability of RINs have been volatile. The Company cannot predict the future prices of RINs and renewable fuel blendstocks, and the costs to obtain the necessary RINs and blendstocks could be material. The Company's financial position and results of operations could be adversely affected if it is unable to pass the compliance costs on to its customers and if the Company pays significantly higher prices for RINs or blendstocks to comply with the RFS mandated standards.

See "Environmental, Social and Governance Considerations - Climate Change."

Climatic Conditions

Extreme climatic conditions may also have material adverse effects on the Company's financial condition and results of operations. Weather and climate affect demand, and therefore, the predictability of the demand for energy is affected to a large degree by the predictability of weather and climate. In addition, the Company's exploration, production and construction operations, and the operations of major customers and suppliers, can be affected by extreme weather. This may result in cessation or diminishment of production, delay of exploration and development activities or delay of plant construction.

The Company operates in some of the harshest environments in the world, including offshore NL. Climate change may increase the frequency of severe weather conditions in these locations including winds, flooding and variable temperatures, which are contributing to the melting of northern ice and increased creation of icebergs. Icebergs off the coast of NL may threaten Atlantic oil production facilities, cause damage to equipment and possible production disruptions, spills, other asset damage and human impacts.

Transition

In addition to emissions regulations and the physical risks of climate change, climate-related transition risks could have a material adverse effect on the Company's business, financial condition and results of operations, and could adversely impact the Company's reputation. For example, increased opposition to companies in the oil sands industry could lead to constrained access to insurance, liquidity and capital and changes in demand for the Company's products, which may impact revenue. Any increases in GHG emissions by the Company could lead to additional taxes and levies, which would increase the costs associated with certain projects. The potential need to develop new technologies to reduce the intensity of GHG emissions could require significant capital investment. Further, the Company may become subject to climate change litigation initiated by third parties. The Company's management monitors these risks and reports to the Board through management's Enterprise Risk Management framework.

Overall, the Company is not able to estimate at this time the degree to which climate change related regulatory, climatic conditions, and transition risks could impact the Company's financial and operating results.

Cybersecurity Threats

As an oil and gas producer, the Company's ability to operate effectively is dependent upon developing and maintaining information systems and infrastructure that support the financial and general operating aspects of the business. Concurrently, the oil and gas industry has become the subject of increased levels of cybersecurity threats.

The Company has security measures, policies and controls designed to protect and secure the integrity of its information technology systems. The Company takes a proactive approach by continuing to invest in technology, processes and people to help minimize the impact of the changing cyber landscape and enhance the Company's resilience to cyber incidents. However, cybersecurity threats frequently change and require ongoing monitoring and detection capabilities. Such cybersecurity threats include unauthorized access to information technology systems due to hacking, viruses and other causes for purposes of misappropriating assets or sensitive information, corrupting data or causing operational disruption. Cyber attacks could result in the loss or exposure of confidential information related to retail credit card information, personnel files, exploration activities, corporate actions, executive officer communications and financial results. The significance of any such event is difficult to quantify, but if the breach is material in nature, it could adversely affect the financial performance of the Company, its operations, its reputation and its standing and expose it to regulatory consequences and claims of third-party damage, all of which could materially adversely affect the Company's results of operations and financial condition if the situation is not resolved in a timely manner, or if the financial impact of such adverse effects is not alleviated through insurance policies.

Although to date the Company has not experienced any material losses relating to cyber attacks or other information security breaches, there can be no assurance that the Company will not incur such losses in the future. The Company's risk and exposure to these matters cannot be fully mitigated because of, among other things, the evolving nature of these threats.

International Operations

International operations can expose the Company to uncertain political, economic and other risks. The Company's operations in certain jurisdictions may be materially adversely affected by political, economic or social instability or events. These events may include, but are not limited to, onerous fiscal policy, renegotiation or nullification of agreements and treaties, imposition of onerous regulation, changes in laws governing existing operations, financial constraints, including currency restrictions and exchange rate fluctuations, unreasonable taxation and behaviour of public officials, joint venture partners or third-party representatives that could result in lost business opportunities for the Company. This could materially adversely affect the Company's interest in its foreign operations, results of operations and financial condition.

Litigation, Administrative Proceedings and Regulatory Actions

The Company may be subject to litigation, claims, administrative proceedings and regulatory actions, which may be material. Such claims could relate to environmental damage, climate change and the impacts thereof, failure to comply with applicable laws and regulations, breach of contract, tax, bribery and employment matters, which could result in an unfavourable decision, including fines, sanctions, monetary damages, temporary suspensions of operations or the inability to engage in certain operations or transactions. The outcome of such claims can be difficult to assess or quantify and may have a material adverse effect on the Company's reputation, financial condition and results of operations. The defence to such claims may be costly and could divert management's attention away from day-to-day operations.

Foreign Currency

The Company's results are affected by the exchange rates between various currencies including the Canadian and U.S. dollars. The majority of the Company's expenditures are in Canadian dollars while most of the Company's revenues are received in U.S. dollars from the sale of oil and gas commodities that receive prices determined by reference to U.S. benchmark prices. An increase in the value of the Canadian dollar relative to the U.S. dollar will decrease the revenues received from the sale of oil and gas commodities. Correspondingly, a decrease in the value of the Canadian dollar relative to the U.S. dollar will increase the revenues received from the sale of oil and gas commodities. In addition, a change in the value of the Canadian dollar against the U.S. dollar will result in an increase or decrease in the Company's U.S. dollar-denominated debt and related interest expense, as expressed in Canadian dollars. The fluctuations in exchange rates are beyond the Company's control and could have a material adverse effect on the Company's results of operations and financial condition.

The Company enters into short-dated foreign exchange contracts to fix the exchange rate for conversion of U.S. dollar denominated revenue to hedge against these potential fluctuations. The Company also designates its U.S. denominated debt as a hedge of the Company's net investment in selected foreign operations with a U.S. dollar functional currency.

Interest Rate

Interest rate risk is the impact of fluctuating interest rates on financial condition. In order to manage interest rate risk and the resulting interest expense, the Company mitigates some of its exposure to interest rate changes by maintaining a mix of both fixed and floating rate debt through the use of its credit facilities and various financial instruments. The optimal mix maintained will depend on market conditions. The Company may also enter into interest rate swaps from time to time as an additional means of managing current and future interest rate risk.

Counterparty Credit

Credit risk represents the financial loss that the Company would suffer if the Company's counterparties in a transaction fail to meet or discharge their obligation to the Company. The Company actively manages this exposure to credit and contract execution risk from both a customer and a supplier perspective. Internal credit policies have governed the Company's credit portfolio and have limited transactions according to a counterparty's and a supplier's credit quality. Counterparties for financial derivatives transacted by the Company are generally major financial institutions or counterparties with investment grade credit ratings.

Liquidity

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they become due. Liquidity risk also includes the risk of not being able to liquidate assets in a timely manner at a reasonable price. The Company's process for managing liquidity risk includes ensuring, to the extent possible, that it has access to multiple sources of capital.

Debt Covenants

The Company's credit facilities include financial covenants, which contain a consolidated debt to total capitalization covenant. If the Company does not comply with the covenants under these credit facilities, there is a risk that repayment could be accelerated.

Competition

The energy industry is highly competitive with respect to gaining access to the resources required to increase oil and gas reserves and production, and gaining access to markets. The Company competes with others to acquire prospective lands, retain drilling capacity and field operating and construction services, obtain sufficient pipeline and other transportation capacity, gain access to and retain adequate markets for its products and services and gain access to capital markets. The Company's ability to successfully complete development projects could be materially adversely affected if it is unable to acquire economic supplies and services due to competition. Subsequent increases in the cost of or delays in acquiring supplies and services could result in uneconomic projects. The Company's competitors comprise all types of energy companies, some of which have greater resources.

Credit Rating Risk

Credit ratings affect the Company's ability to obtain both short-term and long-term financing and the cost of such financing. Additionally, the ability of the Company to engage in ordinary course derivative or hedging transactions and maintain ordinary course contracts with customers and suppliers on acceptable terms depends on the Company's credit ratings. A reduction in the current rating on the Company's debt by one or more of its rating agencies, particularly a downgrade below investment grade ratings, or a negative change in the Company's ratings outlook could materially adversely affect the Company's cost of financing and its access to sources of liquidity and capital. Credit ratings are intended to provide investors with an independent measure of credit quality of any issuer of securities. The credit ratings accorded to the Company's securities by the rating agencies are not recommendations to purchase, hold or sell the securities in as much as such ratings do not comment as to market price or suitability for a particular investor. Any rating may not remain in effect for any given period of time or may be revised or withdrawn entirely by a rating agency in the future if in its judgment circumstances so warrant.

General Economic Conditions

General economic conditions may have a material adverse effect on the Company's results of operations and financial condition. A decline in economic activity will reduce demand for petroleum products and adversely affect the price the Company receives for its commodities. The Company's cash flow could decline, assets could be impaired, future access to capital could be restricted and major development projects could be delayed or abandoned.

Cost or Availability of Oil and Gas Field Equipment

The cost or availability of oil and gas field equipment may adversely affect the Company's ability to undertake exploration, development and construction projects. The oil and gas industry is cyclical in nature and is prone to shortages of supply of equipment and services including drilling rigs, geological and geophysical services, engineering and construction services and construction materials. These materials and services may not be available when required at reasonable prices. Without compromising safety, overall quality and environmental impacts, the Company continually develops its approved suppliers base to provide undisrupted access to materials, equipment and services, while maintaining a competitive cost baseline via cost escalation mitigation strategies.

Financial Controls

While the Company has determined that its disclosure controls and procedures and internal controls over financial reporting are effective, such controls can only provide reasonable assurance with respect to financial statement preparation and disclosure. Failure to prevent, detect and correct misstatements could have a material adverse effect on the Company's results of operations and financial condition.

Possible Failure to Realize Anticipated Benefits of the Cenovus Transaction

Cenovus and Husky completed the Cenovus Transaction to create an integrated energy leader and realize certain benefits including, among other things, potential synergies and cost savings. Achieving the benefits of the Cenovus Transaction depends in part on successfully consolidating functions and integrating operations, procedures and personnel in a timely and efficient manner, as well as the combined company's ability to realize the anticipated growth opportunities and synergies from integrating the respective businesses of Cenovus and Husky following completion of the Cenovus Transaction.

Achieving the benefits of the Cenovus Transaction also depends on the ability of the combined company to effectively capitalize on its scale, scope and leadership position in the oil sands and wider oil and natural gas industry, to realize the anticipated capital and operating synergies, to profitably sequence the growth prospects of its asset base and to maximize the potential of its improved growth opportunities and capital funding opportunities as a result of combining the businesses and operations of Cenovus and Husky.

The integration of the Cenovus and Husky assets will require the dedication of substantial management effort, time and resources which may divert management's focus and resources from other strategic opportunities and from operational matters. The integration process may result in the loss of key employees and the disruption of ongoing business and employee relationships that may adversely affect the combined company's ability to achieve the anticipated benefits of the Cenovus Transaction. A variety of factors, including those other risk factors set forth in this AIF may adversely affect the ability to achieve the anticipated benefits of the Cenovus Transaction.

Entry into New Business Activities

Completion of the Cenovus Transaction has resulted in a combination of the business activities previously carried on by each of Husky and Cenovus as separate entities. The combination of these activities into the combined company may expose shareholders to different business risks than those to which they were exposed prior to the completion of the Cenovus Transaction. As a result of the changing risk profile of the companies, the combined company may be subject to review of its credit ratings, which may result in a downgrade or negative outlook being assigned to the combined company.

Most operational and strategic decisions and certain staffing decisions with respect to integration have not yet been made. These decisions and the integration of the two companies will present challenges to management, including the integration of systems, policies and personnel of the two companies which may be geographically separated, unanticipated liabilities and unanticipated costs. It is possible that the integration process could result in the loss of key employees, the disruption of the respective ongoing businesses or inconsistencies in standards, controls, procedures and policies that adversely affect the ability of management to maintain relationships with customers, suppliers, employees and other constituencies or to achieve the anticipated benefits of the Cenovus Transaction. The performance of the combined company's operations could be adversely affected if the combined company cannot retain key employees to assist in the integration and operation of Husky and Cenovus.

Any inability of management to successfully integrate the operations could have a material adverse effect on the business, financial condition and results of operations of the combined company.

Ongoing Impacts of the COVID-19 Pandemic

The recent COVID-19 pandemic, and actions taken, and that may be taken, by governmental authorities in response thereto, have resulted and may continue to result in, among other things: increased volatility in financial markets and foreign currency exchange rates; disruptions to global supply chains; adverse effects on the health and safety of the Company's workforce, or guidelines or restrictions to protect health and safety of such workforces, rendering employees unable to work or travel; temporary operational restrictions; and an overall slowdown in the global economy. In particular, the COVID-19 pandemic has resulted in, and may continue to result in, a reduction in the demand for, and prices of, commodities that are closely linked to the Company's financial performance, including crude oil, refined petroleum products (such as jet fuel, diesel and gasoline), natural gas and electricity, and also increases the risk that storage for crude oil and refined petroleum products could reach capacity in certain geographic locations in which the Company operates. A prolonged period of decreased demand for, and prices of, these commodities, and any applicable storage constraints, could also result in the Company voluntarily curtailing or shutting in production and a decrease in the Company's refined product volumes and refinery utilization rates, which could adversely impact the Company's business, financial condition and results of operations.

The COVID-19 pandemic continues to rapidly evolve and its effect on supply and demand patterns is expected to result in negative impacts on the Company's business, financial condition and results of operations over the near term. To the extent that the COVID-19 pandemic adversely affects the Company's business, financial condition and results of operations, it may also have the effect of heightening many of the other risks described in this AIF, such as risks relating to: the Company's ability to maintain its credit ratings; financing ongoing project development costs, including costs associated with the Company's joint venture arrangements; meeting the Company's financial obligations; and otherwise complying with the covenants contained in the agreements that govern the Company's indebtedness.

HUSKY EMPLOYEES

The following table shows the number of Husky's permanent employees as at the dates indicated:

	As at December 31,		
	2020	2019	2018
Number of permanent employees	**4,600**	4,802	5,157

DIVIDENDS

Dividend Amounts

The following table shows the aggregate amount of the dividends declared payable per share in respect of Husky's last three financial years ended December 31, for the Company's common shares, Series 1 Preferred Shares, Series 2 Preferred Shares, Series 3 Preferred Shares, Series 5 Preferred Shares and Series 7 Preferred Shares:

	2020	2019	2018
Dividends per Common Share	**$ 0.16**	$ 0.50	$ 0.40
Dividends per Series 1 Preferred Share	**$ 0.60**	$ 0.60	$ 0.60
Dividends per Series 2 Preferred Share	**$ 0.66**	$ 0.85	$ 0.74
Dividends per Series 3 Preferred Share	**$ 1.17**	$ 1.13	$ 1.13
Dividends per Series 5 Preferred Share	**$ 1.14**	$ 1.13	$ 1.13
Dividends per Series 7 Preferred Share	**$ 1.07**	$ 1.15	$ 1.15

On April 29, 2020, the Board reduced the quarterly common share cash dividend to $0.0125 per share from $0.125 per share, as a result of deteriorating market conditions and the Company's focus on its balance sheet.

Dividend Policy and Restrictions

The declaration and payment of dividends are at the discretion of the Board, which will consider earnings, commodity price outlook, future capital requirements and financial condition of Husky, the satisfaction of the applicable solvency test in Husky's governing corporate statute, the ABCA and other relevant factors. Upon completion of the Cenovus Transaction, Cenovus holds all of the Company's common shares, Series 1 Preferred Shares, Series 2 Preferred Shares, Series 3 Preferred Shares, Series 5 Preferred Shares and Series 7 Preferred shares.

Common Share Dividends

The Board has the ability to declare dividends in common shares or in cash.

Series 1 Preferred Share Dividends

Holders of Series 1 Preferred Shares were entitled to receive a cumulative quarterly fixed dividend, payable on the last day of March, June, September and December in each year, of 4.45% annually for the initial period ending March 31, 2016, as and when declared by the Board. Thereafter, the dividend rate resets every five years at a rate equal to the five-year Government of Canada bond yield plus 1.73%. Holders of Series 1 Preferred Shares had the right, at their option, to convert their shares into Series 2 Preferred Shares, subject to certain conditions, on March 31, 2016. In the first quarter of 2016, Husky announced it did not intend to exercise its right to redeem the Series 1 Preferred Shares on March 31, 2016. As a result, the holders of the Series 1 Preferred Shares had the right to choose to retain any or all of their Series 1 Preferred Shares and continue to receive an annual fixed rate dividend paid quarterly, or convert, on a one-for-one basis, any or all of their Series 1 Preferred Shares into Series 2 Preferred Shares, and receive a floating rate quarterly dividend. Holders of Series 1 Preferred Shares receive the new fixed rate quarterly dividend applicable to the Series 1 Preferred Shares of 2.404% for the five-year period commencing March 31, 2016 to, but excluding, March 31, 2021. Effective March 31, 2016, Husky had 10,435,932 Series 1 Preferred Shares issued and outstanding. Holders of the Series 1 Preferred Shares will have the opportunity to convert their shares again on March 31, 2021, and on March 31 every five years thereafter as long as the shares remain outstanding.

Series 2 Preferred Share Dividends

Holders of the Series 2 Preferred Shares were entitled to receive a cumulative quarterly floating rate dividend, payable on the last day of March, June, September and December in each year, at a rate equal to the 90-day Government of Canada Treasury Bill yield plus 1.73% as and when declared by the Board. Effective March 31, 2016, Husky had 1,564,068 Series 2 Shares issued and outstanding. Holders of the Series 2 Shares have the right, at their option, to convert their shares into Series 1 Preferred Shares, subject to certain conditions, on March 31, 2021, and on March 31 every five years thereafter as long as the shares remain outstanding.

Series 3 Preferred Share Dividends

Holders of the Series 3 Shares were entitled to receive a cumulative quarterly fixed dividend, payable on the last day of March, June, September and December in each year, of 4.50% annually for the initial period ending December 31, 2019 as declared by the Board. Thereafter, the dividend rate resets every five years at the rate equal to the five-year Government of Canada bond yield plus 3.13%. Holders of Series 3 Shares had the right, at their option, to convert their shares into Series 4 Preferred Shares, subject to certain conditions, on December 31, 2019. In the fourth quarter of 2019, Husky announced it did not intend to exercise its right to redeem the Series 3 Preferred Shares on December 31, 2019. As a result, the holders of the Series 3 Preferred Shares had the right to choose to retain any or all of their Series 3 Preferred Shares and continue to receive an annual fixed rate dividend paid quarterly, or convert, on a one-for-one basis, any or all of their Series 3 Preferred Shares into Series 4 Preferred Shares, and receive a floating rate quarterly dividend. Holders of the Series 3 Preferred Shares will receive the new fixed rate quarterly dividend applicable to the Series 3 Preferred Shares of 4.689% for the five-year period commencing December 31, 2019 to, but excluding, December 31, 2024. Effective December 31, 2019, Husky had 10,000,000 Series 3 Preferred Shares issued and outstanding and no Series 4 Preferred Shares were issued due to conditions for the conversion into Series 4 Preferred Shares not being satisfied. Holders of the Series 3 Preferred Shares will have the opportunity to convert their shares again on December 31, 2024, and on December 31 every five years thereafter as long as the shares remain outstanding.

Series 5 Preferred Share Dividends

Holders of the Series 5 Preferred Shares were entitled to receive a cumulative quarterly fixed dividend, payable on the last day of March, June, September and December in each year, of 4.50% annually for the initial period ending March 31, 2020 as declared by the Board. Thereafter, the dividend rate resets every five years at the rate equal to the five-year Government of Canada bond yield plus 3.57%. Holders of Series 5 Preferred Shares had the right, at their option, to convert their shares into Series 6 Preferred Shares, subject to certain conditions, on March 31, 2020. In the first quarter of 2020, Husky announced it did not intend to exercise its rights to redeem the Series 5 Preferred Shares on March 31, 2020. As a result, the holders of the Series 5 Preferred Shares had the right to choose to retain any or all of their Series 5 Preferred Shares and continue to receive an annual fixed rate dividend paid quarterly, or convert, on a one-for-one basis, any or all of their Series 5 Preferred Shares into Series 6 Preferred Shares, and receive a floating rate quarterly dividend. Holders of the Series 5 Preferred Shares will receive the new fixed rate quarterly dividend applicable to the Series 5 Preferred Shares of 4.591% for the five-year period commencing March 31, 2020 to, but excluding March 31, 2025. Effective March 31, 2020, Husky had 8,000,000 Series 5 Preferred Shares issued and outstanding and no Series 6 Preferred Shares were issued due to conditions for the conversion into Series 6 Preferred Shares not being satisfied. Holders of the Series 5 Preferred Shares will have the opportunity to convert their shares again on March 31, 2025, and on March 31 every five years thereafter as long as the shares remain outstanding.

Series 7 Preferred Share Dividends

Holders of the Series 7 Preferred Shares were entitled to receive a cumulative fixed dividend, payable on the last day of March, June, September and December in each year, of 4.60% annually for the initial period ending June 30, 2020 as declared by the Board. Thereafter, the dividend rate resets every five years at the rate equal to the five-year Government of Canada bond yield plus 3.52%. Holders of the Series 7 Preferred Shares had the right, at their option, to convert their shares into Series 8 Preferred Shares, subject to certain conditions, on June 30, 2020 and on June 30 every five years thereafter. In second quarter of 2020, Husky announced it did not intend to exercise its rights to redeem the Series 7 Preferred Shares on June 30, 2020. As a result, the holders of the Series 7 Preferred Shares had the right to choose to retain any or all of their Series 7 Preferred Shares and continue to receive an annual fixed rate dividend paid quarterly, or convert, on a one-for-one basis, any or all of their Series 7 Preferred Shares into Series 8 Preferred Shares, and receive a floating rate quarterly dividend. Holders of the Series 7 Preferred Shares receive the new fixed rate quarterly dividend applicable to the Series 7 Preferred Shares of 3.935% for the five-year period commencing June 30, 2020 to, but excluding, June 30, 2025. Effective June 30, 2020, Husky had 6,000,000 Series 7 Preferred Shares issued and outstanding and no Series 8 Preferred Shares were issued due to conditions for the conversion into Series 8 Preferred Shares not being satisfied. Holders of the Series 7 Preferred Shares will have the opportunity to convert their shares again on June 30, 2025, and on June 30 every five years thereafter as long as the shares remain outstanding.

DESCRIPTION OF CAPITAL STRUCTURE

Common Shares

Husky is authorized to issue an unlimited number of no par value common shares. The holders of common shares are entitled to receive notice of and attend all meetings of shareholders, except meetings at which only holders of a specified class or series of shares are entitled to vote, and are entitled to one vote per common share held. Holders of common shares are also entitled to receive dividends as declared by the Board on the common shares payable in whole or in part as a stock dividend in fully paid and non-assessable common shares or by the payment of cash. Holders are also entitled to receive the remaining property of Husky upon dissolution in equal rank with the holders of all other common shares.

Preferred Shares

Husky is authorized to issue an unlimited number of no par value preferred shares. The preferred shares as a class have attached thereto the rights, privileges, restrictions and conditions set forth below.

The preferred shares may from time to time be issued in one or more series, and the Board may fix from time to time before such issue the number of preferred shares which is to comprise each series and the designation, rights, privileges, restrictions and conditions attached to each series of preferred shares including, without limiting the generality of the foregoing, any voting rights, the rate or amount of dividends or, the method of calculating dividends, the dates of payment thereof, the terms and conditions of redemption, purchase and conversion if any, and any sinking fund or other provision.

The preferred shares of each series shall, with respect to the payment of dividends and the distribution of assets or return of capital in the event of liquidation, dissolution or winding up of Husky, whether voluntary or involuntary, or any other return of capital or distribution of assets of Husky amongst its shareholders for the purpose of winding up its affairs, be entitled to preference over the common shares of Husky and over any other shares of Husky ranking by their terms junior to the preferred shares of that series. The preferred shares of any series may also be given such other preferences over the common shares of Husky and any other such preferred shares.

If any cumulative dividends or amounts payable on the return of capital in respect of a series of preferred shares are not paid in full, all series of preferred shares shall participate ratably in respect of accumulated dividends and return of capital.

In 2011, Husky issued 12 million Series 1 Preferred Shares and authorized the issuance of 12 million Series 2 Preferred Shares. In 2014, Husky issued 10 million Series 3 Preferred Shares and authorized the issuance of 10 million Series 4 Preferred Shares. In 2015, Husky issued 8 million Series 5 Preferred Shares and 6 million Series 7 Preferred Shares and authorized the issuance of 8 million Series 6 Preferred Shares and 6 million Series 8 Preferred Shares. See "Dividends — Dividend Policy and Restrictions — Series 1 Preferred Share Dividends" and "Dividends — Dividend Policy and Restrictions — Series 2 Preferred Share Dividends" and "Dividends — Dividend Policy and Restrictions — Series 3 Preferred Share Dividends" and "Dividends — Dividend Policy and Restrictions — Series 5 Preferred Share Dividends" and "Dividends — Dividend Policy and Restrictions — Series 7 Preferred Share Dividends". None of the issued preferred shares is entitled to vote, except in accordance with the provisions of the ABCA.

Husky may, at its option, redeem all or any number of the then outstanding Series 1 Preferred Shares, subject to certain conditions, on March 31, 2021 and on March 31 every five years thereafter. Husky may, at its option, redeem all or any number of the then outstanding Series 2 Preferred Shares, subject to certain conditions, on March 31, 2021 and on March 31 every five years thereafter. Husky may, at its option, redeem all or any number of the then outstanding Series 3 Preferred Shares, subject to certain conditions, on December 31, 2024 and on December 31 every five years thereafter. Husky may, at its option, redeem all or any number of the then outstanding Series 5 Preferred Shares, subject to certain conditions, on March 31, 2025 and on March 31 every five years thereafter. Husky may, at its option, redeem all or any number of the then outstanding Series 7 Preferred Shares, subject to certain conditions, on June 30, 2025 and on June 30 every five years thereafter.

Liquidity Summary

Overview

The following information relating to Husky's current credit ratings is provided as it relates to Husky's financing costs, liquidity and operations. Specifically, credit ratings affect Husky's ability to obtain short-term and long-term financing and the cost of such financing. Additionally, the Company's ability to engage in certain collateralized business activities on a cost effective basis depends on Husky's credit ratings. A reduction in the current rating on Husky's debt by one or more of its rating agencies, particularly a downgrade below investment grade ratings, or a negative change in Husky's ratings outlook could adversely affect Husky's cost of financing and its access to sources of liquidity and capital. In addition, changes in credit ratings may affect Husky's ability to enter, and the associated costs of entering, (i) into ordinary course derivative or hedging transactions, which may require Husky to post additional collateral under certain of its contracts if certain adverse events occur with respect to credit ratings, and (ii) into, and maintaining, ordinary course contracts with customers and suppliers on acceptable terms.

With the announcement of the Cenovus Transaction on October 25, all rating agencies adjusted their ratings opinions.

On October 25, 2020, DBRS Morningstar ("**DBRS**") placed Husky's issuer rating and senior unsecured notes and debentures rating of "BBB(high)", commercial paper rating of R-2(high) and preferred shares - cumulative rating of Pfd-3(high) Under Review with Negative Implications.

On October 25, 2020, Standard and Poor's Rating Services ("**S&P**") placed Husky's "BBB" long-term issuer credit and senior unsecured debt rating and P-3(high) preferred share ratings on CreditWatch with Negative Implications.

On October 26, 2020, Moody's Investor Services ("**Moody's**") placed Husky's "Baa2" senior unsecured ratings On Review for Downgrade.

As at December 31, 2020, Husky had the following credit ratings:

	S&P	Moody's	DBRS
Outlook/Trend	On CreditWatch with Negative Implications	On Review for Downgrade	Under Review with Negative Implications
Senior Unsecured Debt	BBB	Baa2	BBB (high)
Series 1 Preferred Shares	P-3(high)		Pfd-3(high)
Series 2 Preferred Shares	P-3(high)		Pfd-3(high)
Series 3 Preferred Shares	P-3(high)		Pfd-3(high)
Series 5 Preferred Shares	P-3(high)		Pfd-3(high)
Series 7 Preferred Shares	P-3(high)		Pfd-3(high)
Commercial Paper			R-2(high)

With the closing of the Cenovus Transaction announced on January 4, 2021, S&P, Moody's, DBRS and Fitch Ratings ("**Fitch**") finalized their rating opinions.

On January 4, 2021, DBRS downgraded Husky's issuer rating and senior unsecured notes and debentures rating to "BBB" from "BBB (high)", preferred shares ratings to "Pfd-3" from "Pfd-3 (high)", and commercial paper to "R-2 (middle)" from "R-2 (high)" and assigned a stable outlook removing the ratings from Under Review with Negative Implications assigned on October 25, 2020.

On January 4, 2021, S&P lowered Husky's long-term issuer credit and senior unsecured debt rating to "BBB-" from "BBB" and preferred share ratings to "P-3" from "P-3(High)" and assigned a stable outlook, removing the CreditWatch with Negative Implications previously assigned on October 25, 2020.

On January 4, 2021, Moody's downgraded Husky's senior unsecured rating to "Baa3" from "Baa2" and assigned a negative outlook, removing the Under Review assigned on October 26, 2020.

On January 4, 2021, with Husky being a wholly-owned subsidiary of Cenovus, Fitch assigned a "BB+/RR4" rating to Husky's senior unsecured debt and assigned a positive outlook.

Husky's preferred shares were exchanged for Cenovus preferred shares pursuant to the Cenovus Transaction and those preferred share ratings have moved to Cenovus. DBRS has also discontinued and withdrawn its rating on Husky's commercial paper at the request of the Company.

Husky currently has the following credit ratings:

	S&P	Moody's	DBRS	Fitch
Outlook/Trend	Stable	Negative	Stable	Positive
Senior Unsecured Debt	BBB-	Baa3	BBB	BB+

Credit ratings are intended to provide investors with an independent measure of credit quality of any issuer of securities. The credit ratings accorded to Husky's securities by the rating agencies are not recommendations to purchase, hold or sell the securities in as much as such ratings do not comment as to market price or suitability for a particular investor. Any rating may not remain in effect for any given period of time or may be revised or withdrawn entirely by a rating agency in the future if, in its judgment, circumstances so warrant. The Company pays an annual fee to S&P, Moody's and DBRS. Additionally, Husky has paid fees to S&P, Moody's and DBRS in order to receive ratings for debt or equity instruments upon issuance and for rating evaluation or assessment services in connection with the Cenovus Transaction.

Moody's

Moody's long-term credit ratings 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 within the fourth highest of nine categories and is assigned to debt securities which are judged to be medium-grade and subject to moderate credit risk and as such may possess certain speculative characteristics. The addition of a 1, 2 or 3 modifier after a rating indicates the relative standing within a particular rating category. The modifier 2 indicates a ranking in the mid-range of that generic rating category. The modifier 3 indicates a ranking in the lower end of that generic rating category. An "Under Review" outlook indicates a rating is under consideration for change in the near term. A "Negative" outlook indicates a possible rating downgrade over the medium term.

Standard and Poor's

S&P's long-term credit ratings are on a rating scale that ranges from AAA to D, which represents the range from highest to lowest quality of such securities rated. A rating of BBB by S&P is within the fourth highest of 10 categories and indicates that the obligation exhibits adequate protection parameters. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitment on the obligation. A rating of P-3 (high) by S&P on the Canadian preferred share rating scale is equivalent to a BB+ rating on the long-term credit rating scale. The addition of a "+" or "-" designation after a rating indicates the relative standing within the major rating categories. An S&P rating outlook assesses the potential direction of a long-term credit rating over the intermediate term (typically six months to two years). In determining a rating outlook, consideration is given to any changes in the economic and/or fundamental business conditions. A "CreditWatch with Negative Implications" outlook indicates that a rating is placed under special surveillance and may be lowered. A "Stable" outlook indicates that a rating is not likely to change.

DBRS

DBRS's long-term credit ratings are on a rating scale that ranges from AAA to D, which represents the range from highest to lowest quality of such securities rated. A rating of BBB(high) by DBRS is within the fourth highest of 10 categories and is assigned to debt securities considered to be of adequate credit quality. The capacity for payment of financial obligations is acceptable. Entities in the BBB category may be vulnerable to future events. The assignment of a "(high)" or "(low)" modifier within each rating category indicates relative standing within such category. 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-2(high) by DBRS is the fourth highest of 10 categories and is assigned to debt securities considered to be of adequate credit quality. The capacity for the payment of short-term financial obligations as they become due is acceptable. Entities in this category may be vulnerable to future events. The R-1 and R-2 commercial paper categories are denoted by (high), (middle) and (low) designations. DBRS preferred share ratings range from Pdf-1 (highest) to D (lowest). According to the DBRS ratings system, preferred shares rated Pfd-3 are generally of adequate credit quality where protection of dividends and principal is considered acceptable, but the issuing entity is more susceptible to adverse changes in financial and economic conditions, and there may be other adverse conditions present which detract from debt protection. An "Under Review with Negative Implications" outlook signals that the rating is likely to be lowered. A "Stable" outlook indicates that a rating is not likely to change.

Fitch

Fitch's long-term credit ratings are on a rating scale that ranges from AAA to D, which represents the range from highest to lowest quality of such securities rated. A rating of BB+ is within the fifth highest of 11 categories and is assigned to debt securities considered to be speculative. BB+ ratings indicate an elevated vulnerability to default risk, particularly in the event of adverse changes in business or economic conditions over time; however, business or financial flexibility exists that supports the servicing of financial commitments. 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. A Positive outlook indicates an upward trend on the rating scale. 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.

MARKET FOR SECURITIES

Husky's common shares, Series 1 Preferred Shares, Series 2 Preferred Shares, Series 3 Preferred Shares, Series 5 Preferred Shares, and Series 7 Preferred Shares were listed and posted for trading on the TSX under the respective trading symbols "HSE", "HSE.PR.A", "HSE.PR.B", "HSE.PR.C", "HSE.PR.E" and "HSE.PR.G". The Series 1 Preferred Shares began trading on the TSX on March 18, 2011. The Series 2 Preferred Shares began trading on the TSX on March 31, 2016. The Series 3 Preferred Shares began trading on the TSX on December 9, 2014. The Series 5 Preferred Shares began trading on the TSX on March 12, 2015. The Series 7 Preferred Shares began trading on the TSX on June 17, 2015.

All of the above-referenced shares were delisted from the TSX at the close of trading on January 5, 2021.

The following table discloses the trading price range and volume of Husky's common shares traded on the TSX during Husky's financial year ended December 31, 2020:

	High	Low	Volume *(000's)*
January	10.80	8.58	38,621
February	8.96	6.12	48,717
March	6.56	2.21	140,213
April	5.09	3.33	110,891
May	4.44	3.38	102,740
June	6.05	3.83	97,809
July	4.84	3.94	52,629
August	5.00	4.33	39,851
September	4.48	3.02	50,915
October	3.84	2.85	87,486
November	5.89	3.42	53,373
December	6.69	5.18	49,857

The following table discloses the trading price range and volume of the Series 1 Preferred Shares traded on the TSX during Husky's financial year ended December 31, 2020:

	High	Low	Volume *(000's)*
January	12.69	11.16	563
February	11.90	10.00	99
March	10.63	4.10	1,517
April	6.99	4.71	1,000
May	6.51	5.61	152
June	7.54	6.00	185
July	6.88	5.95	211
August	7.25	6.65	168
September	7.19	5.81	212
October	6.70	5.86	286
November	8.42	6.25	481
December	9.71	8.18	615

The following table discloses the trading price range and volume of the Series 2 Preferred Shares traded on the TSX during Husky's financial year ended December 31, 2020:

	High	Low	Volume *(000's)*
January	12.50	11.49	29
February	12.20	11.10	19
March	11.30	4.28	63
April	6.85	5.00	153
May	6.58	5.71	47
June	7.41	6.06	79
July	7.33	6.11	32
August	7.45	6.56	23
September	7.37	5.76	35
October	6.80	5.78	21
November	8.21	6.34	41
December	9.46	8.28	41

The following table discloses the trading price range and volume of the Series 3 Preferred Shares traded on the TSX during Husky's financial year ended December 31, 2020:

	High	Low	Volume *(000's)*
January	18.25	17.19	412
February	17.80	15.91	143
March	15.96	6.58	498
April	11.51	8.05	630
May	11.50	10.20	267
June	12.00	10.60	126
July	13.49	10.80	158
August	13.81	11.92	410
September	13.85	11.20	151
October	12.97	11.03	353
November	15.46	12.01	451
December	16.78	15.00	322

The following table discloses the trading price range and volume of the Series 5 Preferred Shares traded on the TSX during Husky's financial year ended December 31, 2020:

	High	Low	Volume *(000's)*
January	19.60	18.70	85
February	19.50	16.61	171
March	17.09	6.89	319
April	12.42	8.01	660
May	11.64	10.50	156
June	12.75	10.99	110
July	14.20	11.05	106
August	14.45	12.66	68
September	14.35	11.60	160
October	13.30	11.05	245
November	16.00	12.60	254
December	17.68	15.33	334

The following table discloses the trading price range and volume of the Series 7 Preferred Shares traded on the TSX during Husky's financial year ended December 31, 2020:

	High	Low	Volume *(000's)*
January	19.45	18.53	54
February	19.31	16.77	139
March	17.24	6.56	331
April	10.89	7.65	689
May	10.76	9.95	174
June	11.50	10.19	186
July	13.45	10.11	167
August	14.00	12.02	55
September	13.88	10.78	67
October	13.00	10.42	283
November	15.30	11.61	379
December	17.20	15.13	393

DIRECTORS AND OFFICERS

Directors

The following are the names and residences of the directors of Husky as of the date of this AIF, their positions and offices with Husky and their principal occupations for at least the five preceding years. Each director will hold office until the Company's next annual meeting or until his or her successor is appointed or elected.

Fok, Canning K. N.

(Non-independent)
Hong Kong Special Administrative Region

Director since August 25, 2000

Mr. Fok is an Executive Director and Group Co-Managing Director of CK Hutchison Holdings Limited. Mr. Fok has been a director of Cenovus Energy Inc. since January 2021.

Mr. Fok is Chairman and a Director of Hutchison Telecommunications Hong Kong Holdings Limited, Hutchison Telecommunications (Australia) Limited, Hutchison Port Holdings Management Pte. Limited as the trustee-manager of Hutchison Port Holdings Trust, Power Assets Holdings Limited, HK Electric Investments Manager Limited as the trustee-manager of HK Electric Investments, and HK Electric Investments Limited. Mr. Fok is Deputy Chairman and an Executive Director of CK Infrastructure Holdings Limited, and a Non-Executive Director of TPG Telecom Limited.

Mr. Fok obtained a Bachelor of Arts degree from St. John's University, Minnesota in 1974 and a Diploma in Financial Management from the University of New England, Australia in 1976. He has been a member of the Institute of Chartered Accountants in Australia (which amalgamated with the New Zealand Institute of Chartered Accountants to become Chartered Accountants Australia and New Zealand) since 1979 and has been a Fellow of the Chartered Accountants Australia and New Zealand since 2015.

Board & Committee Memberships (2020)	Meeting Attendance	
Board of Directors	4 of 4	100%

Publicly Traded Company Directorships	Committee Memberships	Listing Exchange
CK Hutchison Holding Limited	N/A	Hong Kong
CK Infrastructure Holdings Limited	N/A	Hong Kong
Power Assets Holdings Limited	Remuneration Committee	Hong Kong
HK Electric Investments Limited	Remuneration Committee	Hong Kong
Hutchison Telecommunications Hong Kong Holdings Limited	Nomination Committee Remuneration Committee	Hong Kong
Hutchison Telecommunications (Australia) Limited	Governance, Nomination & Compensation Committee (Chairman)	Australia
Hutchison Port Holdings Management Pte. Limited as trustee manager of Hutchison Port Holdings Trust	N/A	Singapore
TPG Telecom Limited	N/A	Australia
Cenovus Energy Inc.	N/A	TSX, New York

Equity Ownership

Year	Common Shares	DSUs	Market Value as at December 31 (based on closing price on last trading day of the year)
2020	255,365	Nil	$1,613,907

Kwok, Eva L. (Independent) British Columbia, Canada	Mrs. Kwok is Chairman, a Director and Chief Executive Officer of Amara Holdings Inc. (a private investment holding company). Mrs. Kwok has been a director of Cenovus Energy Inc. since January 2021. Mrs. Kwok is also a Director of CK Life Sciences Int'l., (Holdings) Inc., CK Infrastructure Holdings Limited and the Li Ka Shing (Canada) Foundation.
Member of the Audit Committee	Mrs. Kwok was a Director of Shoppers Drug Mart Corporation from 2004 to 2006 and of the Bank of Montreal Group of Companies from 1999 until March 2009.
Director since August 25, 2000	Mrs. Kwok obtained a Master's degree in Science from the University of London in 1967.

Board & Committee Memberships (2020)	Meeting Attendance	
Board of Directors	4 of 4	100%
Compensation Committee	3 of 3	100%
Corporate Governance Committee	3 of 3	100%

Publicly Traded Company Directorships	Committee Memberships	Listing Exchange
CK Life Sciences Int'l., (Holdings) Inc.	Remuneration Committee (Chair)	Hong Kong
CK Infrastructure Holdings Limited	Nomination Committee (Chair)	Hong Kong
Cenovus Energy Inc.	Human Resources and Compensation Committee Nominating and Corporate Governance Committee	TSX, New York

Equity Ownership

Year	Common Shares	DSUs	Market Value as at December 31 (based on closing price on last trading day of the year)
2020	10,215	149,420	$944,336

Shaw, Wayne E. (Independent) Ontario, Canada	Mr. Shaw is the President of G.E. Shaw Investments Limited (a private investment holding company). Mr. Shaw has been a director of Cenovus Energy Inc. since January 2021. Prior to his retirement in April 2013, he was a Senior Partner with Stikeman Elliott LLP, Barristers and Solicitors, Toronto, Ontario. Mr. Shaw is also a Director of the Li Ka Shing (Canada) Foundation.
Member of the Audit Committee	Mr. Shaw holds a Bachelor of Arts degree and a Bachelor of Laws degree, both received from the University of Alberta in 1967. He is a member of the Law Society of Ontario.
Director since August 25, 2000	

Board & Committee Memberships (2020)	Meeting Attendance	
Board of Directors	4 of 4	100%
Audit Committee	4 of 4	100%
Corporate Governance Committee	3 of 3	100%
Health, Safety and Environment Committee	2 of 2	100%

Publicly Traded Company Directorships	Committee Memberships	Listing Exchange
Cenovus Energy Inc.	Audit Committee Safety, Environment, Responsibility and Reserves Committee	TSX, New York

Equity Ownership

Year	Common Shares	DSUs	Market Value as at December 31 (based on closing price on last trading day of the year)
2020	16,343	58,077	$367,049

Sixt, Frank J.

(Non-independent)
Hong Kong Special Administrative Region

Chair of the Audit Committee

Director since August 25, 2000

Mr. Sixt is an Executive Director, Group Finance Director and Deputy Managing Director of CK Hutchison Holdings Limited. Mr. Sixt has been a director of Cenovus Energy Inc. since January 2021.

Mr. Sixt is also the Non-Executive Chairman of TOM Group Limited, an Executive Director of CK Infrastructure Holdings Limited, a Non-Executive Director of TPG Telecom Limited, a Director of Hutchison Telecommunications (Australia) Limited (HTAL) and an Alternate Director to a Director of HTAL, HK Electric Investments Manager Limited as the trustee-manager of HK Electric Investments and HK Electric Investments Limited. Mr. Sixt is also a Director of the Li Ka Shing (Canada) Foundation.

Mr. Sixt obtained a Master's degree in Arts from McGill University, Canada in 1978 and a Bachelor's degree in Civil Law from Université de Montréal in 1978. He is a member of the Bar and of the Law Society of the Provinces of Quebec and Ontario, Canada.

Board & Committee Memberships (2020)	Meeting Attendance	
Board of Directors	4 of 4	100%
Compensation Committee	3 of 3	100%

Publicly Traded Company Directorships	Committee Memberships	Listing Exchange
CK Hutchison Holding Limited	Sustainability Committee (Chair)	Hong Kong
CK Infrastructure Holdings Limited	N/A	Hong Kong
Hutchison Telecommunications (Australia) Limited	Audit & Risk Committee	Australia
TOM Group Limited	Remuneration Committee	Hong Kong
TPG Telecom Limited	Governance, Remuneration & Nomination Committee	Australia
Cenovus Energy Inc.	Nominating and Corporate Governance Committee	TSX, New York

Equity Ownership

Year	Common Shares	DSUs	Market Value as at December 31 (based on closing price on last trading day of the year)
2020	70,190	Nil	$443,601

Officers

The following are the names and residences of the executive officers of Husky Energy Inc. as of the date of this AIF, their positions and offices with Husky Energy Inc. and their principal occupations for at least the five preceding years.

Name and Residence	Office or Position	Principal Occupation During Past Five Years
Hart, Jeffrey R. Alberta, Canada	Acting Chief Executive Officer & Chief Financial Officer	Executive Vice-President & Chief Financial Officer of Cenovus since January 2021. Chief Financial Officer of Husky from November 2018. Acting Chief Financial Officer of Husky from April 2018 to November 2018. Vice President, Controller of Husky Oil Operations Limited from February 2015 to April 2018.
Dahlin, Andrew Alberta, Canada	Acting Chief Operating Officer	Executive Vice-President, Safety & Operations Technical Services of Cenovus since January 2021. Executive Vice President, Downstream & Midstream of Husky from November 2020. Executive Vice President, Western Canada Upstream of Husky from May 2020 to November 2020. Senior Vice President, Heavy Oil & Oil Sands of Husky Oil Operations Limited from May 2018 to April 2020. Senior Vice President, Heavy Oil of Husky Oil Operations Limited from June 2017 to May 2018. Vice President, Upstream of Husky Oil Operations Limited from April 2012 to May 2017.
Robert M. Hinkel (Hong Kong Special Administrative Region)	Chief Operating Officer, Offshore	Senior Vice-President, Asia Pacific Region of Cenovus since January 2021. Chief Operating Officer, Offshore of Husky since April 16, 2020. Chief Operating Officer, Asia Pacific of Husky Oil Operations Limited from December 2010 to April 2020.
Girgulis, James D. Alberta, Canada	Senior Vice President, General Counsel & Secretary	Senior Vice President, General Counsel & Secretary of Husky since April 2012.

As at February 3, 2021, the directors and executive officers of Husky Energy Inc., as a group, beneficially owned or controlled or directed, directly or indirectly, nil common shares of Husky.

Conflicts of Interest

The executive officers and directors of Husky may also become officers and/or directors of other companies engaged in the oil and gas business generally and which may own interests in oil and gas properties in which Husky holds or may in the future, hold an interest. As a result, situations may arise where the interests of such directors and officers conflict with their interests as directors and officers of other companies. In the case of the directors, the resolution of such conflicts is governed by applicable corporate laws that require that directors act honestly, in good faith and with a view to the best interests of Husky and, in respect of the ABCA, Husky's governing statute that directors declare, and refrain from voting on, any matter in which a director may have a conflict of interest.

Corporate Cease Trade Orders or Bankruptcies

None of those persons who are directors or executive officers of Husky is, or has been within the past 10 years, a director, chief executive officer or chief financial officer of any company, including Husky and any personal holding companies of such person that, while such person was acting in that capacity, was the subject of a cease trade or similar order or an order that denied the Company access to any exemption under securities legislation, for a period of more than 30 consecutive days, or after such persons ceased to be a director, chief executive officer or chief financial officer of the Company was the subject of a cease trade or similar order or an order that denied the Company access to any exemption under securities legislation, for a period of more than 30 consecutive days, which resulted from an event that occurred while such person was acting in such capacity.

In addition, none of those persons who are directors or executive officers of Husky is, or has been within the past 10 years, a director or executive officer of any company, including Husky and any personal holding companies of such persons, that while such 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.

Individual Penalties, Sanctions or Bankruptcies

None of the persons who are directors or executive officers of Husky (or any personal holding companies of such persons) has, within the past 10 years, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or were subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold his or her assets.

None of the persons who are directors or executive officers of the Company (or any personal holding companies of such persons) has been subject to any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or have entered into a settlement agreement with a securities regulatory authority or been subject to 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.

EXTERNAL AUDITOR SERVICE FEES

The following table provides information about the fees billed to the Company for professional services rendered by KPMG LLP, the Company's external auditors, during the fiscal years indicated:

($ thousands)	**2020**	2019
Audit Fees	**3,999**	4,133
Audit-related Fees	**424**	235
Tax Fees	**105**	283
	4,528	4,651

Audit fees consist of fees for the audit of the Company's annual financial statements or services that are normally provided in connection with statutory and regulatory filings, including the *Sarbanes-Oxley Act of 2002*. Audit-related fees included fees for attest services not required by statute or regulation. Tax fees included fees for tax planning and various taxation matters.

The Audit Committee has the sole authority to review in advance, and grant any appropriate pre-approvals of, all non-audit services to be provided by the independent auditors and to approve fees in connection therewith. The Audit Committee pre-approved all of the audit-related and tax services provided by KPMG LLP in 2020.

PRINCIPAL HOLDERS OF VOTING SECURITIES

Cenovus Energy Inc. holds 1,005,121,738 common shares, which represent 100% of the Company's voting securities.

EXECUTIVE COMPENSATION

Compensation Discussion and Analysis

Husky's Compensation Committee was appointed by the Board to oversee the development and implementation of the Company's executive compensation program (the **"Compensation Program"**) and ensure alignment with the delivery of shareholder value. Among its responsibilities, the Compensation Committee reviewed and approved the President & Chief Executive Officer's compensation recommendations for the Company's executive officers and also reviewed and monitored the design and competitiveness of major new compensation programs for the Company and its operating subsidiaries. See "Executive Compensation - Compensation Committee Mandate".

All members of the Compensation Committee had the skills and experience to fulfill their responsibilities and to make decisions on the suitability of the Company's compensation policies and practices. They developed skills and experience in making executive compensation decisions through leadership positions within large organizations and through serving on compensation committees of other large publicly-traded companies. Their collective experience in handling executive compensation matters was broad in nature and included experience within a diverse range of industries.

Performance in 2020

The Company marked good progress on its goal to become a High Reliability Organization and a global top-quartile safety performer. This was Husky's primary objective and the Company delivered improvements on several critical metrics, particularly in the reduction of significant process safety incidents. Husky also took a major step forward by setting targets to reduce its carbon intensity, move toward net zero emissions by 2050 and to set gender diversity targets for senior executives positions.

On the financial front, Husky finished the year with operating costs trending about $400 million below 2019. Capital spending was managed down to $1.65 billion, less than half the original budget of $3.7 billion and net debt was in the range of $5.5 billion. If not for Husky's swift and aggressive actions on capital and operating costs in early spring 2020, the Company's debt would have likely exceeded $8.5 billion due to the precipitous drop in prices and margins due to COVID-19 and the global economic fallout. In 2020, Husky maintained its investment-grade credit ratings.

On the operations side, there were many highlights:

- Both Spruce Lake Central and the 29-1 field at Liwan were brought onstream ahead of schedule and under budget.
- Completion of a major turnaround at the Lloyd Upgrader without a single lost-time incident, despite having 3,000 workers on site. At the same time, increasing the diesel capacity at the Upgrader, which improved competitive positioning.
- While work was slowed by COVID-19, the Superior Refinery rebuild has progressed safely.
- The upstream and downstream worked together to continue to optimize value capture in extreme market conditions.

The Compensation Committee's decisions have been based on the achievement of specific corporate and individual performance-related objectives. The Company's strategic objectives in 2020 included:

- to rapidly move towards achieving top-quartile process and occupational safety performance;
- to formulate and execute a corporate strategy which maintains a strong balance sheet, while preserving the Company's growth opportunities;
- to continue to strengthen the core Integrated Corridor and Offshore business by lowering average production and throughput costs while expanding margin capture;
- to ensure strict financial discipline aimed at maintaining a strong balance sheet;
- to create shareholder value through responsible growth and ESG risk management;
- to ensure a robust management succession plan is in place; and
- to identify significant risks to the Company's businesses and ensure mitigation strategies are established.

All of the factors and results discussed above assisted in the evaluation of individual performance and impacted compensation decisions for 2020, as they formed the basis for the calculation of the corporate multiplier applied to the short-term incentive program. Paying for performance forms the basis for the Company's compensation objectives and philosophy.

Compensation Objectives and Philosophy

The Compensation Program was intended to attract, motivate, reward and retain the management talent needed to achieve the Company's business objectives and create long-term value for shareholders. It consisted of base salary, short-term incentives (annual bonuses) and long-term incentives (performance share units ("**PSUs**") and stock options). Based on a pay-for-performance philosophy, it rewarded executive officers on the basis of individual performance and achievement of corporate objectives.

The Board, with the President & Chief Executive Officer, developed a long term strategic plan for the Company. From the long-term plan annual corporate milestones were established and individual performance contracts for each executive officer were set, all with the objective of achieving the long term strategic plan.

Base salary and short-term incentives primarily rewarded executive officers for delivering results on annual milestones, and were important to incentivize executive officers to work towards the common goals of the Company and the shareholders. However, the Compensation Program was designed to contain significant pay at risk, with base salary comprising less than 35% of the target total compensation. The Compensation Program was intentionally more heavily weighted towards performance based elements of compensation.

Long-term incentive awards focus executive officers to make decisions that not only achieve annual milestones, but also continue to deliver results over the longer term. The long-term incentive program was weighted 80% to a Performance Share Unit Plan (the "**PSU Plan**") that with vesting targets aligned with the achievement of corporate measures, including relative total shareholder return ("**TSR**") against a pre-defined peer group. The remaining 20% of the long-term incentive award was provided in stock options. Stock options provided value to executive officers with share price appreciation. If the share price appreciated, shareholders saw more value and the compensation of the executive officers increased accordingly. Without share price appreciation, executive officers received less compensation through their long-term incentive plans, thus reinforcing the Company's pay-for-performance philosophy. The Company elected not to use restricted share units, which carry no performance condition, in order to ensure better alignment with shareholders.

Risk Mitigation

The Compensation Program was designed to provide executive officers incentives for the achievement of near-term and long-term objectives, without motivating them to take unnecessary risk. As part of its review and discussion of the Compensation Program, the Compensation Committee noted the following facts:

- all the directors, including the members of the Compensation Committee, have been regularly apprised of the Company's financial and operating performance throughout the year and the risk characteristics of corporate decisions;
- executive compensation has been tied to the overall results of the Company, both financial and operational, with consideration given to personal performance as it relates to the bonus award;
- the annual incentive program features capped payouts so as not to encourage excessive risk taking;

- there has been an effective balance, in each case, between cash and equity mix, near-term and long-term focus, corporate and individual performance, and financial and non-financial performance;
- the Company's approach to performance evaluation and compensation has provided greater rewards to an executive officer achieving both short-term and long-term agreed upon objectives;
- an Anti-Hedging Policy had been adopted (see "Executive Compensation - Executive Equity Compensation Anti-Hedging Policy");
- a Clawback Policy had been adopted (see "Executive Compensation - Clawback Policy"); and
- a Share Ownership Guideline Policy was implemented effective January 2019 (see "Executive Compensation - Share Ownership Guideline Policy").

Compensation Governance

Succession Planning

The Compensation Committee was entrusted with the responsibility of overseeing the Company's succession planning for senior executive officer roles. As part of this process the Compensation Committee reviewed, at least annually, the succession plan for the Company's senior executive officers. This involved a review of the positions and an evaluation of the qualifications and experience needed to fill these roles. In some instances, internal candidates were identified and evaluated to determine their strengths and areas in need of development. The Compensation Committee reported annually to the Board on the effectiveness of the succession planning processes.

Compensation Process

The President & Chief Executive Officer recommended to the Compensation Committee the individual compensation packages for the executive officers. The Compensation Committee took these recommendations into consideration when making final decisions on compensation for those executive officers. Compensation decisions regarding the President & Chief Executive Officer were made entirely by the Compensation Committee and were based primarily on the achievement of individual and corporate goals and objectives including long-term strategic objectives.

The Company participated in annual executive compensation surveys (the **"Surveys"**) conducted by Willis Towers Watson. The Surveys looked at base salaries and other short-term and long-term incentive programs in effect at the Company's peer companies in Canada and were used, along with the disclosure in such peer companies' annual management information circulars, as a reference by the Compensation Committee to assess the competitiveness of the Compensation Program. In the case of executive officers, compensation was targeted at the 50th percentile of the remuneration paid to executive officers who operated in similar business environments and whose positions were of similar capacity, scope and complexity.

The Compensation Committee reviewed the list of the Company's peer companies to ensure their continued appropriateness. The peer group for 2020 was:

Canadian Natural Resources Limited	Cenovus Energy Inc.	Enbridge Inc.
Imperial Oil Limited	Nutrien Ltd.	Ovintiv Inc. (1)
Pembina Pipeline Corporation	Suncor Energy Inc.	TC Energy Corporation
Teck Resources Limited		

(1) Ovintiv Inc. (formerly Encana Corporation) relocated its headquarters to the U.S. in early 2020. Husky did not remove Ovintiv Inc. from its peer group once it was re-domiciled.

In choosing the peer companies, the Compensation Committee selected: (i) commodity-cyclical, resource-based companies with integrated operations; (ii) similarly-sized (as measured by annual revenue) energy companies headquartered or with significant operations in Canada; and (iii) similarly-sized (as measured by assets) capital-intensive companies operating in Canada. The Compensation Committee believed these metrics were appropriate for determining peers because they provided a reasonable point of reference for comparing executive officers with similar positions and responsibilities as well as representing a source of competition for executive talent.

The Company retained Willis Towers Watson to provide specific analysis on executive compensation in respect of the competitiveness of the Company's compensation practices. The Compensation Committee considered this analysis in making its decisions on all elements of compensation for executive officers.

Executive Compensation External Consultant Fees

The Company continued its engagement of Willis Towers Watson to assist in determining the 2020 compensation for the Company's directors and executive officers. Willis Towers Watson, which has been retained by the Company since at least 2007, has protocols in place to ensure that it is in a position to provide independent advice. While the Compensation Committee considered the information provided by Willis Towers Watson in making its decisions on all elements of compensation for the

Company's executive officers, the Compensation Committee remained wholly responsible for its own decisions, which may have reflected other considerations.

The following table provides information about the fees billed to the Company for services rendered by Willis Towers Watson during the financial years indicated:

($)	2020	2019
Executive Compensation-Related Fees	239,724	178,848

Executive Compensation-Related Fees consist of fees for services related to determining compensation for any of the Company's directors and executive officers. All other fees paid to Willis Towers Watson were $1,772,640 in 2020 and $2,184,632 in 2019 for services related to the review of the Company's long-term incentive plans, the compilation of compensation market data, comparator peer group development, administrative and actuarial services related to the Company's pension and benefits plans, corporate risk and broking services and other general management consulting services.

Elements of Compensation

Base Salary

The base salary of each of the Company's executive officers was determined by the Compensation Committee based on the level of responsibility and the experience of the individual, the relative importance of the position to the Company and the performance of the individual over time. The Compensation Committee believed that a competitive base salary for all employees of the Company was a key factor in achieving and maintaining the Company's desired competitive positioning in the oil and gas industry.

Short-term Incentive Program

The purpose of the short-term incentive program was to relate a component of compensation directly to the achievement of stated annual objectives from a corporate and individual standpoint. Awards were based on overall performance and each executive officer was assessed on the same consistent basis with bonuses being determined only after the Company's financial results for the preceding financial year were known. Actual awards received by executive officers may have been higher or lower than the target bonus opportunity depending on the results. With respect to the Named Executive Officers (as defined under "Executive Compensation - Summary Compensation Table"), the target bonus opportunity and range of opportunity in 2020 were as follows:

Position	Target Bonus Opportunity (percentage of base salary)	Corporate Performance Range of Opportunity	Individual Performance Range of Opportunity
President & Chief Executive Officer	125%	50 – 150%	50 – 150%
Chief Financial Officer	75%	50 – 150%	50 – 150%
Chief Executive Officer, Offshore	57%	50 – 150%	50 – 150%
Executive Vice President, Downstream & Midstream	57%	50 – 150%	50 – 150%
Executive Vice President, Western Canada Upstream	48%	50 – 150%	50 – 150%
Chief Operating Officer	80%	50 – 150%	50 – 150%

The Compensation Committee and the President & Chief Executive Officer developed the corporate scorecard, which formed the basis for the calculation of the corporate multiplier for the short-term incentive program. Corporate performance, for the purpose of calculating the short-term incentive corporate multiplier, was determined through the Board's evaluation of performance of the Company as a whole relative to the annual budget and strategic plan. Specific measures examined included performance against targets for upstream operating unit costs, refinery/upgrading unit costs, production, refinery/upgrading throughput, and reserves replacement.

These metrics were also assessed in relation to performance by the Company's peers. Targets for these metrics were driven by the economic environment and were aligned with the Company's overall strategic objectives, including ESG. As Husky believes the targets provide competitively sensitive information about its operational strategy, and if disclosed would seriously prejudice its interests, it is relying on the exemption in applicable securities laws from disclosing quantitative targets. As these targets were set based on the budget approved by the Board, there was an expectation by the Compensation Committee that the targets would be met.

Weighting	Metric	
50%	**Operating Metrics** The operating metrics used to assess the financial performance of the Company included net debt, upstream/operating cost, refining/upgrading operating cost and headcount.	**Modified by safety factor(1)**
30%	**Production/Reserves** Performance in production took into account the Company's total production, refinery/upgrading throughput and reserves replacement ratio.	
20%	**Qualitative Assessment** The qualitative assessment was based on certain 2020 commercial achievements and the execution of the Company's capital and operations plan.	

(1) The adjustment factor used to apply the value of process and occupational safety, as well as environmental performance to the bonus program. The factor was a rating between 0.8 and 1.2.

Individual performance for an executive officer was determined against achievement of his or her own specific targets as set out in his or her annual performance contract. Executive officer individual objectives were set to support the corporate scorecard and the Company's strategic objectives, including ESG. Key performance metrics were identified and targets were set annually in order to gauge the results of actions undertaken by the President & Chief Executive Officer, the other executive officers and the employees generally in executing the Company's strategic plan. The President & Chief Executive Officer and the Compensation Committee would also evaluate a broad range of qualitative factors, including reliability in delivering financial and growth objectives, a track record of integrity, a good safety record, environmental stewardship, good judgment, the vision and ability to create further growth, the ability to lead others and stewardship through varying economic conditions. This multiplier could vary between 50% and 150%.

Operational safety was expected in the achievement of all of the metrics in the corporate scorecard. To apply the corresponding value of safety to performance, safety did not have its own weighting within the scorecard, but was used as the adjustment factor S to the total overall corporate multiplier as described above.

Long-term Incentive Compensation

To align with short and long-term business performance and shareholder value creation, long-term incentives consisted of a combination of PSUs and stock options. In determining the appropriate long-term incentive fair value granted to the Named Executive Officers (as defined under "Executive Compensation - Summary Compensation Table"), the Compensation Committee considered external market data, as well as other factors such as leadership and talent retention.

In administering long-term incentives for executive officers, the Company granted PSUs and stock options. While PSUs and stock options are both tied to share price, the incentive and retention value of stock options was limited in circumstances where, notwithstanding strong corporate and individual performance, the share price performance was negatively impacted by external factors. Unlike stock options, PSUs continued to provide an incentive for executives to remain with the Company during such periods, continuing to tie compensation to share price performance and comparison to peer company performance. A vested PSU will always have value equal to the share price.

Granting Process for Share-based and Option-based Awards

In determining the size of individual PSU and stock option grants, the Compensation Committee considered the recommendations of the President & Chief Executive Officer, other than with respect to any PSUs and stock options to be granted to the President & Chief Executive Officer, and considered the aggregate number of common shares available under the Company's Incentive Stock Option Plan (the **"Plan"**) and the number of individuals to whom the Company wished to grant PSUs and stock options. The Compensation Committee also considered the range of potential compensation levels that may be yielded by the PSUs and stock options. The Compensation Committee reserved the discretion to consider any factors it considered relevant, including, but not limited to, any previous grants to an executive officer or eligible employee, and to give all factors considered the relative weight it considered appropriate under the circumstances then prevailing, in reaching its determination regarding the size and timing of PSU and stock option grants. PSU and stock option grants to existing eligible employees were made on an annual pre-determined date. Similarly, PSU and stock option grants to newly hired employees and those employees receiving job promotions were made on pre-determined dates during the calendar year.

The Compensation Committee approved the maximum number of PSUs and stock options to be granted for the year, along with the specific PSU and stock option grants for the President & Chief Executive Officer and the other executive officers. The allocations of PSUs and stock options for the annual grant, based on employee level, were approved through the delegation given by the Board to the Compensation Committee. See "Executive Compensation - Long-term Incentive Plans".

Perquisites and Benefit Plans

Along with all other employees, the executive officers participated in the benefit plans provided by the Company. There were no special benefit plans in place for any of the executive officers. The executive officers could participate in a supplemental pension plan that was available to all employees where Husky contributions exceeded the *Income Tax Act* (Canada) maximum pension limits. The Company had a 5% savings plan for all employees, including the executive officers. Employees, including executive officers, could direct all or a portion of their contribution to the savings plan to be used to purchase common shares in the market. The executive officers also received a monthly vehicle allowance and paid parking.

Compensation Decisions for 2020

Base Salary

On May 1, 2020, Mr. Hinkel was promoted to Chief Operating Officer, Offshore and Mr. Dahlin was promoted to Executive Vice President, Western Canada Upstream, which resulted in salary increases of 1.5% and 13.6%, respectively. On November 1, 2020, Mr. Dahlin was promoted to Executive Vice President, Downstream & Midstream and Mr. Alexander was promoted to Executive Vice President, Western Canada Upstream. This resulted in a salary increase for Mr. Alexander of 15.1%.

Short-term Incentive Program

Each executive officer's payment under the short-term incentive program was calculated by applying the executive officer's target bonus opportunity to salary, modified by the individual performance multiplier and then modified by the corporate multiplier. The 2020 corporate multiplier for the short-term incentive program was determined to be 100%, comprised of a 90% assessment on targeted financial and operational metrics multiplied by a safety factor of 1.1 reflecting significant improvements in safety performance.

The individual performance multiplier for an executive officer was determined against achievement of his or her own specific targets as set out in his or her annual performance contract.

Long-term Incentive Grants

The following table outlines the number of PSUs and stock options granted in 2020 to the Named Executive Officers. See "Executive Compensation - Summary Compensation Table" for the corresponding valuations of the PSUs and stock options granted.

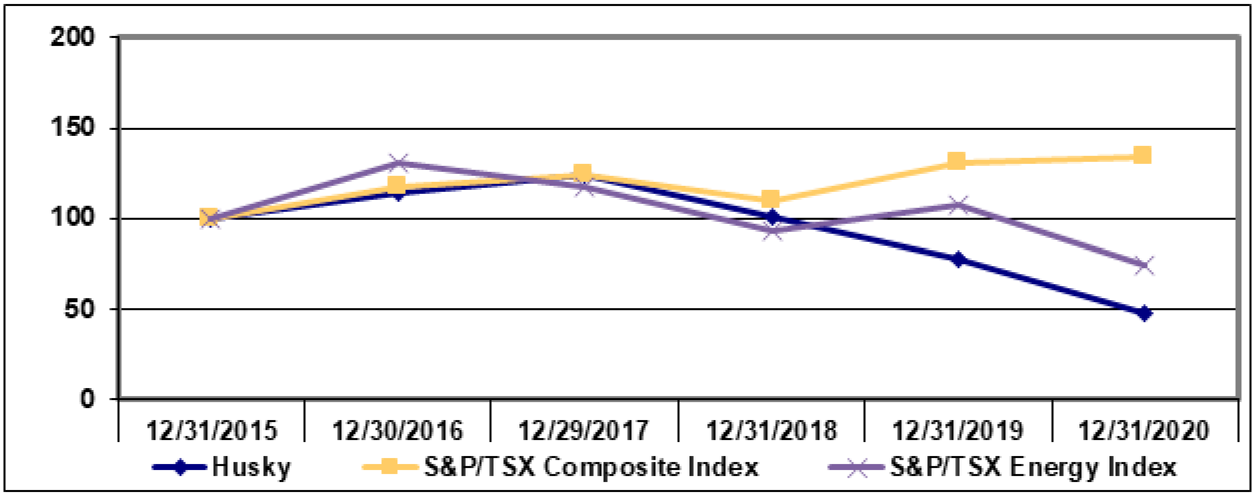
Named Executive Officer	Number of PSUs granted	Number of stock options granted
Robert J. Peabody	573,000	564,500
Jeffrey R. Hart	169,450	167,100
Robert M. Hinkel	137,510	135,490
Andrew Dahlin	137,510	135,490
Gerald F. Alexander	137,510	135,490
Robert W. P. Symonds	252,100	248,400

Total Cost of Compensation

During the financial year ended December 31, 2020, the aggregate compensation amount for the Named Executive Officers (as defined under "Executive Compensation - Summary Compensation Table") was $11,209,884.

Performance Graph

The following performance graph compares the Company's cumulative TSR on Common Shares over the period from December 31, 2015 to December 31, 2020, assuming a $100 initial investment and the reinvestment of all dividends, with the cumulative TSR on the S&P/TSX Composite Index and on the S&P/TSX Energy Index.



	31-Dec-15	31-Dec-16	31-Dec-17	31-Dec-18	31-Dec-19	31-Dec-20
Husky	100	114	124	101	77	48
S&P/TSX Composite Index	100	118	125	110	131	134
S&P/TSX Energy Index	100	131	118	93	108	75

The Company's executive officers receive long-term incentives as part of their compensation. The actual value received from long-term incentives by individual executive officers is proportional to any increase (or decrease) in the market price of Husky's common shares on the TSX. See "Executive Compensation - Compensation Discussion and Analysis - Elements of Compensation - Long-term Incentive Compensation". In reviewing individual executive officer compensation reported in the Summary Compensation Table, there is a general correlation between market price performance of Husky's common shares and the total compensation received by the executive officers for the three-year period disclosed in the Summary Compensation Table.

Summary Compensation Table

The following table details compensation information for the three most recently completed financial years of the Company for the Company's: President & Chief Executive Officer, Robert J. Peabody; Chief Financial Officer, Jeffrey R. Hart; Chief Operating Officer, Offshore, Robert M. Hinkel; Executive Vice President, Downstream & Midstream, Andrew Dahlin; Executive Vice President, Western Canada Upstream, Gerald F. Alexander and retired Chief Operating Officer, Robert W. P. Symonds (collectively, the **"Named Executive Officers"**).

					Non-equity incentive plan compensation ($)				
Name and principal position	Year	Salary $	Share-based awards ($) (1)	Option-based awards ($) (2)	Annual incentive plans (3)	Long-term incentive plans	Pension value ($) (4)	All other compensation ($) (5)	Total Compensation ($)
Robert J. Peabody President & Chief Executive Officer	2020 2019 2018	1,626,000 1,614,500 1,528,750	1,101,822 3,572,474 3,431,528	249,033 838,556 846,703	–(11) 1,053,000 1,738,000	– – –	178,860 177,595 168,163	113,675 179,944 171,132	3,269,390 7,436,069 7,884,275
Jeffrey R. Hart(6) Chief Financial Officer	2020 2019 2018	515,000 511,250 385,604	325,835 1,357,353 962,392	73,717 318,646 406,821	386,300 200,000 171,000	– – –	56,650 56,238 35,232	50,350 50,852 39,963	1,407,852 2,494,340 2,001,013
Robert M. Hinkel(7) Chief Operating Officer, Offshore	2020 2019 2018	700,710 681,032 646,554	331,103 535,824 540,633	101,515 125,772 219,070	516,478 278,649 386,119	– – –	63,064 61,293 58,190	280,355 331,744 351,126	1,993,225 2,014,314 2,201,693
Andrew Dahlin(8) Executive Vice President, Downstream & Midstream	2020 2019 2018	480,000 430,000 395,000	331,103 535,824 570,227	101,515 125,772 241,969	355,300 163,000 194,000	– – –	52,800 47,300 43,133	48,638 46,950 45,144	1,369,356 1,348,846 1,489,473
Gerald F. Alexander(9) Executive Vice President, Western Canada Upstream	2020 2019 2018	427,500 407,500 374,450	385,580 428,603 432,484	153,564 100,632 423,553	245,300 139,000 225,000	– – –	47,025 44,825 37,964	47,593 46,346 54,119	1,306,562 1,166,906 1,547,570
Robert W. P. Symonds(10) Chief Operating Officer (retired)	2020 2019 2018	541,333 806,250 763,250	484,763 1,571,702 1,422,832	109,583 368,951 576,626	– –(12) 521,000	– – –	178,417 88,688 83,958	549,400(11) 65,258 63,260	1,863,497 2,900,847 3,430,924

(1) The accounting grant date fair value of PSUs granted but not vested is based on the number of PSUs multiplied by a valuation ratio of 0.67 and the closing price of Husky's common shares on the TSX on the grant date of the PSUs. The Company uses this methodology as it is a commonly recognized way of calculating a meaningful and reasonable estimate of fair value. In connection with the Cenovus Transaction, all unvested PSUs became vested and were paid out at a valuation ratio of 1.00.

(2) The Company has calculated the accounting grant date fair value of the options granted to Named Executive Officers using the Black-Scholes model. The Company chose this methodology because it is recognized as the most commonly used methodology of valuing options. The Black-Scholes assumptions used by the Company were:

Assumptions	2018	2019	2020
Initial expected useful life	1.95 years (based on option vest date)	1.95 years (based on option vest date)	1.96 years (based on option vest date)
Expected annual dividend	$0.68 per share (based on option grant date)	$0.53 per share (based on option grant date)	$0.39 per share (based on option grant date)
Volatility	28.40% - 31.40% (range within tranches of March grant)	30.17% - 32.22% (range within tranches of March grant)	39.46% - 42.43% (range within tranches of March grant)
Risk-free interest rate	1.83% - 2.08% (range within tranches of March grant)	1.65% (range within tranches of March grant)	0.51% - 0.68% (range within tranches of March grant)

Mr. Hart also received options on August 15, 2018 and December 17, 2018. Mr. Dahlin and Mr. Hinkel received options on August 11, 2020 and Mr. Alexander received options on November 23, 2020. The values of the August 15, 2018 and December 17, 2018 option grants are based on the following assumptions: initial expected useful life of 1.95 years (both grants); expected annual dividend $0.60 per share, $0.56 per share; volatility 29.10% - 32.22% and 30.09% - 31.51%; risk-free interest rate 2.09% - 2.19%, 1.96% - 1.98%. The values of the August 11, 2020 and November 23, 2020 option grants are based on the following assumptions: initial expected useful life 1.98 years, 1.99 years; expected annual dividend $0.27 per share, $0.21 per share; volatility 51.46% - 55.06% and 53.20% - 55.18%; risk-free interest rate 0.28% - 0.38%, 0.27% - 0.44%.

(3) The bonuses disclosed in the table for each year were earned in respect of performance for that year and are paid in the following year.

(4) Represents contributions the Company has made on behalf of the Named Executive Officers to the Retirement Plan (as defined herein), which consists of a Defined Contribution Pension Plan, a non-registered after-tax account for contributions in excess of the income tax limit (for the years prior to 2019), matching contributions and taxable cash. Mr. Peabody, Mr. Hart, Mr. Symonds, Mr. Dahlin, and Mr. Alexander, participated in the Company's Defined Contribution Pension Plan. The amounts in the table also include a supplementary pension plan which was introduced effective January 1, 2019 specifically for Husky contributions that are over the *Income Tax Act* (Canada) pension limits. Husky has maintained a notional account which accumulates with the annual Husky contribution and notional investment income. The notional account is paid out at retirement or when the employee leaves the Company. Employees defer tax until receipt of the notional account. Mr. Hinkel received taxable cash.

(5) Includes executive officer perquisites (parking, vehicle allowances), unused vacation payouts, location premiums and allowances and employer contributions to Company-sponsored benefits and savings plan programs, with the exception of the Retirement Plan (as defined herein), which is shown under the column "Pension value". The items included in the column "All other compensation" are paid in cash or are taxable benefits to the Named Executive Officers and therefore the amounts shown are cash costs to the Company. Other than as indicated, the Named Executive Officers did not receive any perquisites, including property or personal benefits not generally available to all employees, that in aggregate were worth $50,000 or more, or were worth 10% or more of the Named Executive Officer's total salary for the financial year.

(6) Mr. Hart was appointed Acting Chief Financial Officer on April 5, 2018 and Chief Financial Officer on November 16, 2018. He was previously Vice President, Controller of Husky Oil Operations Limited.

(7) All figures for Mr. Hinkel were converted from U.S. dollars, the currency in which Mr. Hinkel is paid, to Canadian dollars using the Bank of Canada annual average exchange rate for the applicable year. For the annual averages for 2018, 2019 and 2020, the exchange rates were $1.2957, $1.3269, and $1.3415, respectively.

(8) Mr. Dahlin was promoted to Executive Vice President, Western Canada Upstream effective May 1, 2020 and to Executive Vice President, Downstream & Midstream effective November 1, 2020.

(9) Mr. Alexander was promoted to Executive Vice President, Western Canada Upstream effective November 1, 2020.

(10) Mr. Symonds retired effective August 31, 2020.

(11) Mr. Peabody's earned bonus for 2020 was included as part of his retirement package paid in 2021.

(12) Mr. Symonds' earned bonus for 2019 was included as part of his retirement package.

Incentive Plan Awards

Outstanding Share-based Awards and Option-based Awards

The following table sets forth information in respect of incentive plan awards outstanding at the end of the financial year ended December 31, 2020 held by the Named Executive Officers.

	Option-based Awards				Share-based Awards		
Name	**Number of securities underlying unexercised options**	**Option exercise price ($)**	**Option expiration date**	**Value of unexercised in-the-money options ($)[(1)]**	**Number of PSUs that have not vested[(2)]**	**Market or payout value of PSUs that have not vested ($)[(3)]**	**Market or payout value of vested PSUs not paid out or distributed ($)**
Robert J. Peabody	135,000	15.67	May 3, 2021	–	1,137,120	7,163,856	–
	317,990	16.16	March 7, 2022	–	–	–	–
	298,300	17.05	March 8, 2023	–	–	–	–
	355,900	14.39	March 7, 2024	–	–	–	–
	564,500	2.77	March 22, 2025	1,992,685	–	–	–
Jeffrey R. Hart	17,250	15.67	May 3, 2021	–	366,638	2,309,819	–
	28,550	16.16	March 7, 2022	–	–	–	–
	28,550	17.05	March 8, 2023	–	–	–	–
	29,330	21.87	August 14, 2023	–	–	–	–
	82,000	15.57	Dec 16, 2023	–	–	–	–
	135,240	14.39	March 7, 2024	–	–	–	–
	167,100	2.77	March 22, 2025	589,863	–	–	–
Robert M. Hinkel	37,921	15.67	May 3, 2021	–	223,494	1,408,012	–
	84,640	16.16	March 7, 2022	–	–	–	–
	77,180	17.05	March 8, 2023	–	–	–	–
	53,380	14.39	March 7, 2024	–	–	–	–
	84,680	2.77	March 22, 2025	298,920	–	–	–
	50,810	4.66	August 10, 2025	83,328	–	–	–
Andrew Dahlin	22,500	15.67	May 3, 2021	–	223,494	1,408,012	–
	33,860	16.16	March 7, 2022	–	–	–	–
	33,850	14.61	August 14, 2022	–	–	–	–
	61,750	17.05	March 8, 2023	–	–	–	–
	15,430	21.87	August 14, 2023	–	–	–	–
	53,380	14.39	March 7, 2024	–	–	–	–
	84,680	2.77	March 22, 2025	298,920	–	–	–
	50,810	4.66	August 10, 2025	83,328	–	–	–
Gerald F. Alexander	18,980	15.67	May 3, 2021	–	206,290	1,299,627	–
	67,710	16.16	March 7, 2022	–	–	–	–
	61,750	17.05	March 8, 2023	–	–	–	–
	42,710	14.39	March 7, 2024	–	–	–	–
	67,740	2.77	March 22, 2025	239,122	–	–	–
	67,750	4.89	November 22, 2025	95,528	–	–	–
Robert W. P. Symonds	63,630	15.67	May 3, 2021	–	411,653	2,593,414	–
	162,520	16.16	March 7, 2022	–	–	–	–
	203,150	17.05	March 8, 2023	–	–	–	–
	156,590	14.39	June 21, 2023	–	–	–	–
	165,600	2.77	June 21, 2023	584,568	–	–	–

(1) Calculated by subtracting the exercise price of the stock options from the closing price of Husky's common shares on the TSX on December 31, 2020 ($6.30) and multiplying the amount by the number of Husky's common shares issuable upon exercise of the options.
(2) Represents the aggregate number of PSUs held as of December 31, 2020.
(3) The market or payout value of PSUs that have not vested was determined by multiplying the number of unvested PSUs by the closing price of Husky's common shares on the TSX on December 31, 2020 ($6.30), which assumes maximum performance. In accordance with the terms of the PSU Plan, actual market or payout

value would be equal to the number of vested PSUs multiplied by Husky's performance factor and by the weighted average trading price of Husky's common shares on the TSX for the five trading days immediately preceding the vesting date.

Incentive Plan Awards - Value Vested or Earned During the Year

The following table sets forth information in respect of the value of incentive plan awards held by the Named Executive Officers that vested during the Company's most recently completed financial year.

Name	Option-based awards - Value vested during the year(1) ($)	Share-based awards - Value vested during the year(2) ($)	Non-equity incentive plan compensation - Value earned during the year (3) ($)
Robert J. Peabody	-	751,975	-
Jeffrey R. Hart	-	112,782	386,300
Robert M. Hinkel	-	144,570	516,478
Andrew Dahlin	-	115,276	355,300
Gerald F. Alexander	-	115,670	245,300
Robert W. P. Symonds	-	308,034	-

(1) Represents the aggregate dollar value that would have been realized if the options had been exercised on the vesting date based on the difference between the closing price of Husky's common shares on the TSX on the vesting date and the exercise price of the options held. Where the vesting date is a weekend or a holiday the most recent closing price immediately prior to the vest date is used.

(2) Amounts shown are actual payments of vested PSUs calculated by multiplying the number of units granted by the applicable performance vesting factor by the weighted average trading price of Husky's common shares on the TSX for the five trading days immediately preceding the applicable vesting date.

(3) Amounts shown are corporate bonus payments related to the 2020 performance year. The figure shown for Mr. Hinkel was converted to Canadian dollars using the Bank of Canada 2020 annual average exchange rate of $1.3415. Mr. Peabody's earned bonus for 2020 was included as part of his retirement package paid in 2021.

Options Exercised during the Year

The following table sets forth information in respect of the number of stock options exercised by the Named Executive Officers and the aggregate value realized upon the exercise of these options during the Company's most recently completed financial year.

Name	Number of Options exercised (#)	Aggregate Value Realized ($)
Robert J. Peabody	-	-
Jeffrey R. Hart	-	-
Robert M. Hinkel	-	-
Andrew Dahlin	-	-
Gerald F. Alexander	-	-
Robert W. P. Symonds	-	-

Performance Share Unit Grants Vested in 2020

PSUs vest on the second and third anniversary dates of the grant date in percentages determined by the Compensation Committee based on the Company meeting the performance conditions the Compensation Committee set at the time of grant. With respect to the outstanding PSUs in 2020, up to 50% of the granted PSUs would have vested based on the TSR ranking within the Company's industry peer group, and up to 50% would have vested based on return on capital in use ("**ROCIU**") (see **"Reader Advisories - Non-GAAP Measures"**) targets set by the Company. See "Executive Compensation - Long-term Incentive Plans".

Two grants of PSUs vested in 2020. PSUs vest on the second and third anniversary dates, resulting in 60% of the 2017 granted PSUs eligible to vest and 40% of the 2018 granted PSUs eligible to vest.

Pursuant to the terms of the PSU Plan, the calculated performance factor for the second vesting tranche of the 2017 PSU grant was 55.08%, resulting in the following payouts:

Named Executive Officer	PSUs granted in 2017 (#)	PSUs Eligible to vest (60%) in 2020 (#)	Performance Factor	Share Price at time of vest ($)	Payout under 2017 Grant vesting in 2020 ($)
Mr. Peabody	246,800	148,080	55.08%	$5.89	$480,403
Mr. Hart	17,640	10,584	55.08%	$5.89	$34,337
Mr. Hinkel	52,290	31,374	55.08%	$5.89	$101,784
Mr. Dahlin	20,920	12,552	55.08%	$5.89	$40,721
Mr. Dahlin	20,920	12,552	55.08%	$4.82	$33,324
Mr. Alexander	41,840	25,104	55.08%	$5.89	$81,443
Mr. Symonds	100,400	60,240	55.08%	$5.89	$195,431

Pursuant to the terms of the PSU Plan, the calculated performance factor for the first vesting tranche of the 2018 PSU grant was 38.08%, resulting in the following payouts:

Named Executive Officer	PSUs granted in 2018 (#)	PSUs Eligible to vest (40%) in 2020 (#)	Performance Factor	Share Price at time of vest ($)	Payout under 2018 Grant vesting in 2020 ($)
Mr. Peabody	302,700	121,080	38.08%	$5.89	$271,572
Mr. Hart	17,640	7,056	38.08%	$5.89	$15,826
Mr. Hart	18,130	7,252	38.08%	$4.82	$13,311
Mr. Hart	50,660	20,264	38.08%	$6.39	$49,309
Mr. Hinkel	47,690	19,076	38.08%	$5.89	$42,786
Mr. Dahlin	38,150	15,260	38.08%	$5.89	$34,227
Mr. Dahlin	9,540	3,816	38.08%	$4.82	$7,004
Mr. Alexander	38,150	15,260	38.08%	$5.89	$34,227
Mr. Symonds	125,510	50,204	38.08%	$5.89	$112,603

Retirement Plan

The Named Executive Officers participated in a Company-sponsored retirement plan (the "**Retirement Plan**") made available to all employees. Under the Retirement Plan, the Company contributed a percentage of an employee's base pay each month into the Company's defined contribution pension plan, and the employee decided how to invest the funds. The contributions made on behalf of employees varied with years of continuous service with the Company, ranging from 5% to 9% of base salary. Effective January 1, 2018, the Company contributed 9% of base salary for management and senior management personnel regardless of years of service. Also effective January 1, 2018, the Company matched 50% of employee contributions up to 2% of base earnings.

A supplementary pension plan was introduced, effective January 1, 2019, specifically for Husky contributions that were over the *Income Tax Act* (Canada) pension limits. Husky maintained a notional account which accumulated with the annual Husky contribution and notional investment income. The notional account was to be paid out at retirement or when the employee left the Company. Employees deferred tax until receipt of the notional account. Where applicable, the following table sets forth information in respect of the Company's defined contribution pension plan payments on behalf of the Named Executive Officers for the Company's most recently completed financial year. Mr. Peabody, Mr. Hart, Mr. Dahlin and Mr. Alexander were enrolled in the Company's defined contribution pension plan as of December 31, 2020. Mr. Hinkel received taxable cash.

Name	Accumulated value at start of year ($)	Compensatory ($)[(1)]	Accumulated value at year end ($)[(2)]
Robert J. Peabody	283,055	178,860	503,719
Jeffrey R. Hart	230,883	56,650	320,346
Robert M. Hinkel	-	-	-
Andrew Dahlin	147,435	52,800	233,100
Gerald Alexander	147,147	52,290	216,949
Robert W. P. Symonds	196,741	59,547	266,332

(1) Represents contributions to the defined contribution pension plan and supplemental pension (effective January 1, 2019).
(2) Includes investment earnings in 2020.

Employment Agreements

All of the Named Executive Officers had Executive Employment Agreements with Husky Oil Operations Limited, the Company's principal operating subsidiary.

The terms of the Executive Employment Agreements provided that in the event of the termination of the Named Executive Officer by the Company without just cause or by the Named Executive Officer following a change of control, the Named Executive Officer would be entitled to receive a retiring allowance consisting of a lump sum cash amount equal to two times the Named Executive Officer's base annual salary plus the continuation of all group benefits for a period of 24 months following the termination of employment, or at the Company's option, in lieu of such continued coverage, an additional cash payment equal to 15% of two times the Named Executive Officer's base annual salary. In addition, pursuant to the Plan, the Board had the authority to accelerate the vesting of all outstanding options held by the Named Executive Officers.

The total amount that would have been payable under the Executive Employment Agreement to each of the Named Executive Officers as at December 31, 2020, assuming a cash payment in lieu of continued benefit coverage, no accrued and unpaid vacation pay and no acceleration of the vesting of unvested options, is set out in the following table:

Name	Salary Related ($)	Benefits Related ($)	Total ($)
Robert J. Peabody	3,252,000	487,800	3,739,800
Jeffrey R. Hart	1,030,000	154,500	1,184,500
Robert M. Hinkel[(1)]	1,408,575	211,286	1,619,861
Andrew Dahlin	1,000,000	150,000	1,150,000
Gerald Alexander	960,000	144,000	1,104,000

(1) Mr. Hinkel is paid in United States dollars. His salary and benefits were converted to Canadian dollars using the Bank of Canada 2020 annual average exchange rate. For the annual average for 2020, the Canadian dollar was at $1.3415.

In the event a Named Executive Officer terminated his Executive Employment Agreement upon a change of control, the Named Executive Officer agreed, at the Company's option, to continue his employment for a period of up to six months following such termination at his existing compensation package, to assist the Company in an orderly transition of management. The Executive Employment Agreements also contained non-competition and standard confidentiality provisions. The Named Executive Officers agreed: (i) that so long as they were employed by the Company, they were not to engage in any practice or business in competition with the business of the Company or any of its affiliates; (ii) that except with the consent of the Board in writing not to disclose any confidential information to any unauthorized persons whether or not the Named Executive Officer continued to be employed by the Company; and (iii) not to, directly or indirectly, solicit any employee or contract personnel for employment or contract position for a period of 12 months following the expiry or termination of their respective Executive Employment Agreements.

In April 2018, the Company began including an anti-compete clause in its Executive Employment Agreements, with an expectation that such a provision would be incorporated into its Executive Employment Agreements on a go-forward basis. The anti-compete clause prohibited the executive officer from working for any Competing Business within a defined territory for a period of 12 months after leaving the Company. Competing Business was defined as any company contained in the list of industry peer group companies used by Husky's Compensation Committee to determine PSU payouts, as published in the Company's most recent management information circular at the time of termination. All of the Named Executive Officers, other than Mr. Dahlin, had signed revised Executive Employment Agreements that included this clause.

Executive Equity Compensation Anti-Hedging Policy

In accordance with the Company's Company Communications, Disclosure and Insider Trading/Reporting Policy, directors and officers of the Company were not permitted, at any time, to:

- engage in the practice of selling "short" securities of the Company;
- engage in the practice of buying or selling a "call" or "put" or any other derivative security in respect of the securities of the Company; or
- enter into any other short or long-term financial transaction that is designed to hedge or offset any decrease in the market value of the Company's securities or which could result in profit from a decrease in the market value of the Company's securities.

Clawback Policy

The Company has in place a Clawback Policy. Pursuant to the Clawback Policy, the Compensation Committee could require that certain key executive officers, as described in the policy, return incentive compensation paid to them if the financial results upon which the awards were based were materially restated due to intentional misconduct or fraud of the executive officer.

In situations where: (i) the amount of incentive compensation received by an executive officer or former executive officer to whom the policy applies was calculated based or contingent upon the achievement of certain financial results that were subsequently the subject of or affected by a material restatement of all or a portion of the Company's financial statements; and (ii) the executive officer or former executive officer engaged in intentional misconduct or fraud that caused, or potentially caused, the need for the restatement, as admitted by the executive officer or, in the absence of such admission, as determined by a court of competent jurisdiction in a final judgment that cannot be appealed; and (iii) the incentive compensation payment received would have been lower had the financial statements been properly reported, then the Compensation Committee may, to the extent permitted by applicable laws and to the extent it determines that it is in the Company's best interest to do so, require reimbursement of the amount by which the after-tax incentive compensation received by such executive officer under the Company's annual and long-term incentive plans exceeded that which the executive officer would have received had the financial statements not been materially restated.

Share Ownership Guideline Policy

The Company adopted a Share Ownership Guideline Policy effective January 1, 2019. The Share Ownership Guideline Policy required the President & Chief Executive Officer and certain other executive officers to hold a minimum number of common shares of the Company.

President & Chief Executive Officer	2 x base annual salary as at December 31st
All other Named Executive Officers	1 x base annual salary as at December 31st

All designated executive officers for which the Share Ownership Guideline Policy applied had seven years to satisfy the requirement from the date each executive was subject to the Policy.

Compensation Committee Mandate

The Company's Compensation Committee Mandate provides as follows:

A. **PURPOSE**

The Compensation Committee (the "Committee") is a committee of the Board of Directors (the "Board") of Husky Energy Inc. (the "Company"). The Committee's primary function is to assist the Board in carrying out its responsibilities with respect to:

1. determining the general compensation structure and benefit programs for the Company, including that such compensation is linked appropriately to corporate performance;
2. determining compensation of the, President and Chief Executive Officer and senior management, including that such compensation is linked appropriately to corporate performance;
3. setting in advance and evaluating the annual performance objectives for the President and Chief Executive Officer and senior management, and advising the Board in this regard;
4. oversight of the succession planning process for the President and Chief Executive Officer and senior management; and

5. oversight of the Company's long term incentive planning, including any stock grant, stock option equity linked or similar plan.

B. COMPOSITION

The Committee will consist of not less than three directors, as determined by the Board, all of whom shall be independent of management.

Members of the Committee will be appointed annually at a meeting of the Board, on the recommendation of the Corporate Governance Committee to the Co-Chairs, and will be listed in the annual report to shareholders.

Committee members may be removed or replaced at any time by the Board, and will, in any event, cease to be a member of the Committee upon ceasing to be a member of the Board. Where a vacancy occurs at any time in the membership of the Committee, it may be filled by the Board.

The Committee Chair will be appointed by the Board, on the recommendation of the Corporate Governance Committee to the Co-Chairs.

C. MEETINGS

The Committee will meet at least once annually at the call of the Chair or any other Committee member, and as many additional times as the Committee deems necessary.

Committee members will strive to be present at all meetings either in person, by telephone or other communications facilities as permit all persons participating in the meeting to hear each other.

A majority of Committee members, present in person, by telephone, or by other permissible communication facilities will constitute a quorum.

The Committee will appoint a secretary who need not be a member of the Committee or a director of the Company. The secretary will keep minutes of the meetings of the Committee. Minutes will be sent to all Committee members, on a timely basis.

D. AUTHORITY

The Committee has the authority to engage and set the compensation of independent counsel and other advisors, at the Company's expense, as it determines necessary to carry out its duties.

E. SPECIFIC DUTIES & RESPONSIBILITIES

The Committee will have the oversight responsibilities and specific duties as described below.

1. Act in an advisory capacity to the Board.
2. Establish industry benchmarks and comparables for the Company's approach to compensation.
3. Determine the compensation of the President and Chief Executive Officer, subject to the terms of any existing contractual arrangements.
4. After considering the recommendation of the President and Chief Executive Officer, to determine:
   (i) the general compensation structure and programs for the Company; and
   (ii) the compensation levels for the senior management.
5. Review the Company's long term incentive plans (including any stock grant, stock option, equity linked or similar plan) and establish, modify or discontinue such plans from time to time as it judges appropriate, and to approve any issuance or allocation under any such plan in relation to any period and the terms thereof.
6. Review and make recommendations to the Board on issues that arise in relation to any employment contracts in force from time to time.
7. Review benefit programs for salaried personnel, when required.
8. Review and approve severance arrangements for senior management.
9. Deliver the annual report to shareholders on executive compensation required to be included in the information circular for the annual general meeting.
10. Review and report annually to the Board on the effectiveness of the succession planning processes of the Company.
11. Review and monitor the overall employment environment of the Company, looking both internally and externally.
12. Carry out such other responsibilities as the Board may from time to time, set forth.

13. Advise and report to the Co-Chairs of the Board and the Board, relative to the duties and responsibilities set out above, from time to time, and in such detail as is reasonably appropriate.

Long-term Incentive Plans

Performance Share Units

PSUs were aligned with the Company's pay-for-performance philosophy in that participants received the value of the PSUs only if performance targets were achieved.

Pursuant to the PSU Plan, the Compensation Committee could grant executive officers and eligible employees PSUs based on certain factors, including: (i) the desire to achieve certain corporate performance measures; (ii) compensation data for comparable benchmark positions among the Company's competitors; (iii) the duties and seniority of the executive officer or eligible employee; (iv) individual and/or departmental contributions and potential contributions to the success of the Company; and (v) such other factors as the Compensation Committee deemed relevant in connection with accomplishing the purposes of the PSU Plan.

PSUs would vest on the second and third anniversary dates of the grant date in percentages determined by the Compensation Committee based on the Company meeting the performance conditions the Compensation Committee set at the time of grant. With respect to the outstanding PSUs in 2020, up to 50% of the granted PSUs would have vested based on the TSR ranking within the Company's industry peer group, and up to 50% would have vested based on ROCIU targets set by the Company. The PSU Plan provides that ROCIU is defined as net earnings of the Company plus after tax interest expense divided by the two year average capital employed, less any capital invested in assets that are not generating cash flows. Net earnings represent actual net earnings of the Company adjusted for the difference between actual realized and budgeted commodity prices and foreign exchange rates and other actual and budgeted exceptional items.

The industry peer group used by the Compensation Committee consisted of comparable North American based public oil and gas issuers and other issuers for which oil and gas operations were a significant business segment, were competitors of the Company and were included in North American equity market energy indices. The peer companies applicable to PSU grants from and after January 1, 2020 for the determination of PSU payouts were:

ARC Resources Ltd.	Canadian Natural Resources Limited
Cenovus Energy Inc.	Chevron Corporation
ConocoPhillips Corp.	Crescent Point Energy
Devon Energy Corporation	Exxon Mobil Corporation
Hess Corp.	Imperial Oil Limited
Marathon Oil Corporation	Murphy Oil Corporation
Occidental Petroleum Corporation	Ovintiv Inc. (1)
Seven Generations Energy Ltd.	Suncor Energy Inc.
Tourmaline Oil Corp.	

(1) Ovintiv Inc. (formerly Encana Corporation) relocated its headquarters to the U.S. in early 2020. Husky did not remove Ovintiv Inc. from its peer group once it was re-domiciled.

The performance factor was on a scale, interpolated between the reference points detailed below:

		50%	50%
Performance level achieved	**Performance Factor applied at vest date (to # of PSUs eligible to vest)**	**TSR ranking (against peer companies point over point over two and three years)**	**ROCIU budget (two and three year averages)**
Below threshold	0%	<25th percentile	<Budget -20%
Threshold performance	33.3%	25th percentile	Budget -20%
Target performance	66.6%	50th percentile	Budget
Maximum performance	100%	75th percentile	Budget +20%
Above maximum	100%	>100th percentile	>Budget +20%

Upon vesting, the holder of the PSUs would receive a cash payment equal to the number of PSUs that vested multiplied by the weighted average trading price of the Company's common shares on the TSX for the five trading days immediately preceding the vesting date less withholding taxes.

The PSUs were non-transferable and, other than in the case of retirement, disability or death, terminated immediately upon the executive officer's or eligible employee's termination with or without cause and upon voluntary resignation. Upon termination, all PSUs held and all rights to receive a cash amount thereafter were forfeited by the grantee. Effective September 1, 2018, the Compensation Committee approved an amendment to the PSU Plan to provide in the event of the grantee's death or retirement PSUs would continue to vest on a prorated basis. The proration was applicable to PSUs granted in the year of death or retirement and was based on the period of active employment starting January 1st of the year of death or retirement with a minimum of six months worked in that calendar year. In the event of disability, the PSUs held by the grantee would generally continue to vest in accordance with their terms.

Incentive Stock Option Plan

The Plan was designed, through the grant of stock options in the appropriate circumstances, to reward executive officers and key employees in relation to the Company's common share price performance. The Plan was an integral component of the Company's total Compensation Program in terms of attracting and retaining key employees and enhancing shareholder value by aligning the interests of executive officers with the growth and profitability of the Company. The longer term focus of this compensation element complemented and balanced the short-term incentive program.

Pursuant to the Plan, the Compensation Committee granted from time to time to executive officers and other eligible employees of the Company (each an "**Eligible Person**") options to purchase the Company's common shares. Stock options were granted to Eligible Persons on an annual basis. Similarly, stock option grants to newly hired employees and those employees receiving job promotions were made on pre-determined dates during the calendar year. Non-executive directors were not Eligible Persons and did not receive stock options.

The exercise price at which common shares may be purchased pursuant to an option was established at the time such stock option was granted and was the weighted average trading price per common share on the TSX for the five trading days preceding the grant date. The term of each stock option was five years, subject to the Board determining at the time of grant that a particular stock option would have a shorter or longer term, provided that no term was to exceed 10 years. Stock options vested as to one-third on each of the first three anniversary dates of the date of grant of the stock options, subject to the right of the Board to determine, at the time of grant, that particular stock options would be exercisable in whole or in part on earlier dates and to determine, after the grant date, that a particular stock option would be exercisable in whole or in part on earlier dates for any reason, including the occurrence of a proposal by the Company or any other person or company to implement a transaction that would, if implemented, result in a change of control (as defined in the Plan).

Eligible Persons could surrender their stock options to the Company in consideration for the receipt by the Eligible Person of an amount in cash equal to the excess of the aggregate fair market value of the common shares able to be purchased pursuant to the vested and exercisable portion of such stock options on the date of surrender over the aggregate exercise price for those common shares pursuant to those stock options. The fair market value of common shares was calculated as the closing price of the common shares on the date on which board lots of common shares traded immediately preceding the date a holder of the stock options provided notice to the Company that he or she wished to surrender his or her stock options to the Company in lieu of exercise.

The stock options were not assignable and terminated immediately upon the Eligible Person being dismissed from his or her employment for cause or resigning at the request of the Company, or terminated after 90 days upon the Eligible Person resigning his or her office or employment (other than at the request of the Company) or upon being dismissed without cause. Effective September 1, 2018, the Compensation Committee approved an amendment to the Plan to provide that in the event of the Eligible Person's retirement, stock options would continue to vest on a prorated basis and all vested stock options would have to be exercised within the earlier of 90 days after the last vest date or the expiry date of the stock options. The proration was applicable to stock options granted in the year of retirement and was based on the period of active employment starting January 1st of the year of retirement, with a minimum of six months worked in that calendar year. Effective November 16, 2018 the Compensation Committee approved an amendment to the Plan to change the vesting of options in the event of death to provide that all unvested options shall vest as of the date of death and may be exercised by the Eligible Person's personal representatives during the period ending 12 months after the death of the Eligible Person. Shareholder approval was not obtained for the amendments made in 2018 as they were amendments of the nature allowed under the Plan to be made by the Compensation Committee without shareholder approval.

Director Compensation

Approach to Director Compensation

In designing a compensation program for non-executive directors, the Board's objective was to ensure that the Company attracted and retained highly qualified, committed and talented members of the Board with an extensive and relevant breadth of experience, as well as to align the interests of directors with those of the shareholders. The effect of the Cenovus Transaction is that the Company became a wholly-owned subsidiary of Cenovus. Effective January 1, 2021, the Board was reconstituted to consist of four directors, being Canning K. N. Fok, Eva L. Kwok, Wayne E. Shaw and Frank J. Sixt. The disclosure in this section relates to the Company's director compensation practices prior to the completion of the Cenovus Transaction.

The Board set the compensation of non-executive directors based on the Corporate Governance Committee's recommendations. The Corporate Governance Committee annually reviewed the compensation of non-executive directors and recommended to the Board such adjustments as it considered appropriate and necessary to recognize the workload, time commitment and responsibility of the members of the Board and Board Committees and to remain competitive with director compensation trends in Canada with comparable companies. The Board sets director compensation at the 50th percentile of that paid to directors by comparative oil and gas industry peer companies. The peer group for 2020 is set out below:

Barrick Gold Corporation	Canadian Natural Resources Limited	Cenovus Energy Inc.
Enbridge Inc.	Nutrien Ltd.	Ovintiv Inc. (1)
Suncor Energy Inc.	Teck Resources Limited	TC Energy Corporation

(1) Ovintiv Inc. (formerly Encana Corporation) relocated its headquarters to the U.S. in early 2020. Husky did not remove Ovintiv Inc. from its peer group once it was re-domiciled.

In April 2019, the Corporate Governance Committee recommended, and the Board approved, increasing the compensation of non-executive directors by including an annual equity grant in the form of DSUs. In the event the grant of DSUs was problematic for any individual non-independent director that director can request that the DSUs be paid out in cash. The annual retainer of the Chair of the Audit Committee was also increased from $20,000 to $25,000.

The Company had a Share Accumulation Plan for Directors whereby the directors could elect to have the cash portion of the fees payable to them paid in the form of the issuance of DSUs and/or used to purchase common shares in the market. Directors were able to elect annually whether they wished for their directors' fees to be so used and could specify a portion of their directors' fees that were to be used for DSUs and/or the purchase of common shares, with the remaining amount of fees paid in cash. A DSU was a bookkeeping entry that tracked the value of one common share. When cash dividends were paid on common shares, eligible directors were credited with additional DSUs. The number of additional DSUs was calculated by multiplying the cash dividend per common share by the number of DSUs in the director's account as of the date of record divided by the fair market value of a common share on the payment date of the dividend. DSUs accumulated over a director's term of service and were not paid out until the director leaves the Board, which provided the director with an ongoing stake in Husky during his or her term of service. When the director left the Board, payment for the DSUs was made in cash or common shares purchased on the open market at the option of the director.

The Company does not have a retirement policy for directors.

The following table sets out the annual fees paid in 2020 to non-executive directors of the Company with no separate meeting attendance fees:

Name & Residence	Annual Retainer (2020)
Director Retainer	$120,000 and $85,000 of DSUs
Chair of Audit Committee	$25,000
Member of Audit Committee	$12,500

The directors of the Company were also entitled to reimbursement for out-of-pocket expenses for attendance at meetings of the Board and any Board Committees. During the financial year ended December 31, 2020, the directors of the Company earned compensation in the aggregate amount of $3,170,000 ($2,223,492 in cash and $946,508 in DSUs).

The Company does not have any security ownership requirements for directors, as the Company is a wholly-owned subsidiary of Cenovus.

The following table sets out the compensation paid to directors of the Company consisting of cash and DSUs for the financial year ended December 31, 2020.

Name	DSUs[(1)]	Board Retainer ($)	Committee Chair Retainer ($)	Committee Member Retainer Fee ($)	Total Fees ($)	As elected by the director Total Fees received in the form of: DSUs ($)	Common Shares ($)	Cash ($)
Victor T. K. Li	—	205,000	—	—	**205,000**	—	—	205,000
Canning K. N. Fok	—	205,000	5,000	—	**210,000**	—	—	210,000
Stephen E. Bradley	21,773	120,000	—	17,500	**222,500**	85,000	—	137,500
Asim Ghosh	21,773	120,000	—	5,000	**210,000**	85,000	—	125,000
Martin J. G. Glynn	21,773	120,000	10,000	17,500	**232,500**	85,000	—	147,500
Poh Chan Koh	—	205,000	—	—	**205,000**	—	—	205,000
Eva L. Kwok	21,773	120,000	—	10,000	**215,000**	215,000	—	—
Stanley T. L. Kwok	21,773	120,000	—	5,000	**210,000**	85,000	—	125,000
Frederick S. H. Ma	21,773	120,000	6,250	14,375	**225,625**	85,000	—	143,750
George C. Magnus	21,773	120,000	—	12,500	**217,500**	85,000	—	132,500
Neil D. McGee	—	205,000	—	5,000	**210,000**	—	—	210,000
Robert J. Peabody[(2)]	—	—	—	—	**—**	—	—	—
Colin S. Russel	21,773	120,000	5,000	17,500	**227,500**	85,000	—	142,500
Wayne E. Shaw	21,773	120,000	—	22,500	**227,500**	85,000	—	142,500
William Shurniak	14,481	72,717	15,150	—	**139,375**	51,508	—	87,867
Frank J. Sixt	—	205,000	2,500	5,000	**212,500**	—	—	212,500

(1) In the event the grant of the DSU portion of their annual retainer is problematic for any individual non-independent director that director could request that those DSUs be paid out in cash.

(2) As an executive office, Mr. Peabody did not receive director fees.

Outstanding Share-based Awards

The following table sets forth information in respect of incentive plan awards outstanding at the end of the financial year ended December 31, 2020 held by the directors of the Company. Non-executive directors of the Company do not receive option-based awards. The share-based awards were in the form of DSUs that were received in accordance with the Share Accumulation Plan for Directors.

	Share-based Awards	
Name	Number of DSUs that have not vested[(2)]	Market or payout value of DSUs that have not vested ($)[(3)]
Victor T. K. Li	—	—
Canning K. N. Fok	—	—
Stephen E. Bradley	25,015	158,096
Asim Ghosh	21,875	138,250
Martin J. G. Glynn	47,995	303,330
Poh Chan Koh	—	—
Eva L. Kwok	149,420	944,335
Stanley T. L. Kwok	25,015	158,096
Frederick S. H. Ma	25,015	158,096
George C. Magnus	68,274	431,493
Neil D. McGee	—	—
Robert J. Peabody[(1)]	—	—
Colin S. Russel	42,440	268,221
Wayne E. Shaw	58,077	367,049
William Shurniak[(4)]	—	—
Frank J. Sixt	—	—

(1) Information with respect to share-based awards and option-based awards held by Mr. Peabody is included under "Executive Compensation – Incentive Plan Awards – Outstanding Share-based Awards and Option-based Awards".

(2) Amounts reported include DSUs credited as dividend equivalents.

(3) Based on the volume-weighted average price (VWAP) of the common shares on the TSX on December 31, 2020 of $6.32.

(4) All 17,714 of Mr. Shurniak's DSUs vested on August 8, 2020.

Value Vested or Earned During the Year

Information with respect to vested option-based awards held by Mr. Peabody is included under "Executive Compensation – Incentive Plan Awards – Incentive Plan Awards – Value Vested or Earned During the Year" for Named Executive Officers (as defined under "Executive Compensation – Summary Compensation Table"). DSUs held by directors do not vest until the director leaves the Board.

In connection with the Cenovus Transaction, all of the directors resigned and all DSUs were paid out.

SECURITIES AUTHORIZED FOR ISSUANCE UNDER EQUITY COMPENSATION PLANS

The following table sets forth information as at December 31, 2020 with respect to the Company's compensation plans under which equity securities of the Company are authorized for issuance.

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights [(1)]	Weighted-average exercise price of outstanding options, warrants and rights ($)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in first column)
Equity compensation plans approved by security holders	18,883,146	$ 12.01	29,549,368
Equity compensation plans not approved by security holders	Nil	N/A	N/A
Total	18,883,146	$ 12.01	29,549,368

(1) All outstanding options were transferred to Cenovus effective January 1, 2021 pursuant to the Cenovus Transaction for options to acquire common shares of Cenovus.

LEGAL PROCEEDINGS

The Company is involved in various claims and litigation arising in the normal course of business. While the outcome of these matters is uncertain and there can be no assurance that such matters will be resolved in the Company's favour, the Company does not currently believe that the outcome of adverse decisions in any pending or threatened proceedings related to these or other matters or any amount which it may be required to pay by reason thereof would have a material adverse impact on its financial condition, results of operations or liquidity.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

None of the Company's directors, executive officers or persons or companies that beneficially own or control or direct, directly or indirectly or a combination of both, more than 10% of Husky's common shares, or their associates and affiliates, had any material interest, direct or indirect, in any transaction with the Company within the three most recently completed financial years or during the current financial year that has materially affected or would reasonably be expected to materially affect the Company.

INTERESTS OF EXPERTS

Certain information relating to the Company's reserves included in this AIF has been calculated by the Company and audited, reviewed and opined upon as at December 31, 2020 by Sproule. Sproule is an independent petroleum engineering consultant retained by Husky, and such reserves information has been so included in reliance on the opinion and analysis of Sproule, given upon the authority of said firm as experts in reserves engineering. The partners, employees and consultants of Sproule, as a group, beneficially own, directly or indirectly, less than 1% of the Company's securities of any class.

KPMG LLP are the auditors of the Company and have confirmed that they are independent with respect to the Company 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.

ADDITIONAL INFORMATION

Additional financial information is provided in Husky's audited consolidated financial statements and management's discussion and analysis ("**MD&A**") for the financial year ended December 31, 2020.

Additional information relating to Husky Energy Inc. is available on the System for Electronic Document Analysis and Retrieval ("**SEDAR**") at www.sedar.com and on the Electronic Data Gathering, Analysis, and Retrieval system ("**EDGAR**") at www.sec.gov.

READER ADVISORIES

Forward-looking Statements

Certain statements in this AIF are forward-looking statements and information (collectively "**forward-looking statements**"), within the meaning of the applicable Canadian securities legislation, Section 21E of the United States *Securities Exchange Act* of 1934, as amended, and Section 27A of the United States *Securities Act* of 1933, as amended. The forward-looking statements contained in this AIF are forward-looking and not historical facts.

Some of the forward-looking statements may be identified by statements that express, or involve discussions as to, expectations, beliefs, plans, objectives, assumptions or future events or performance (often, but not always, through the use of words or phrases such as "will likely result", "are expected to", "will continue", "is anticipated", "is targeting", "estimated", "intend", "plan", "projection", "could", "aim", "vision", "goals", "objective", "target", "schedules" and "outlook"). In particular, forward-looking statements in this AIF include, but are not limited to, references to:

- with respect to the business, operations and results of the Company generally: the Company's GHG emissions intensity reduction targets; the Company's gender diversity target; expected effects of abandonment and reclamation costs, development costs and operating costs on anticipated development or production activities on properties with attributed reserves and on properties with no attributed reserves; scheduled timing of development of the Company's proved and probable undeveloped reserves; expected sources of funding for future development costs; estimates of the forecasted costs of developing the Company's proved and proved plus probable reserves as at December 31, 2020; the Company's 2021 production estimates broken down by product type and location; expected spending in 2021 on ARO and environmental site closure activities in North America; anticipated effects of and cost of compliance with certain future or proposed laws and regulations on the Company's operations; and goal to become a global top-quartile safety performer;

- with respect to the Lloydminster Heavy Oil Value Chain, estimated production and expected timing of first production from the Spruce Lake North project;

- with respect to Oil Sands, the expected timing for production from three additional well pairs at the Sunrise Energy Project; and timing for a scheduled turnaround at the Sunrise Energy Project;

- with respect to U.S. Refining, the scheduled completion for the rebuild of the Superior Refinery; and

- with respect to the Company's Offshore business in Asia Pacific, the scheduled drilling of five MDA field production wells and two MBH field production wells, and the expected timing of first gas sales therefrom; the expected timing of development and tie-in of the additional MDK shallow water field; and timing for final investment decision for the MAC field development and expected timing for first production if the decision is made to proceed with the development.

In addition, statements relating to "reserves" are deemed to be forward-looking statements as they involve the implied assessment based on certain estimates and assumptions that the reserves described can be profitably produced in the future. There are numerous uncertainties inherent in estimating quantities of reserves and in projecting future rates of production and the timing of development expenditures. The total amount or timing of actual future production may vary from reserve and production estimates.

Although the Company believes that the expectations reflected by the forward-looking statements presented in this AIF are reasonable, the Company's forward-looking statements have been based on assumptions and factors concerning future events that may prove to be inaccurate. Those assumptions and factors are based on information currently available to the Company about itself and the businesses in which it operates. Information used in developing forward-looking statements has been acquired from various sources, including third party consultants, suppliers and regulators, among others. The material factors and assumptions used to develop the forward-looking statements include, but are not limited to:

- with respect to the business, operations and results of the Company generally: the absence of significant adverse changes to commodity prices, interest rates, applicable royalty rates and tax laws, and foreign exchange rates; the absence of significant adverse changes to energy markets, competitive conditions, the supply and demand for crude oil, conventional natural gas, NGL and refined petroleum products, or the political, economic and social stability of the jurisdictions in which the Company operates; continuing availability of economical capital resources, labour and services; demand for products and cost of operations; the absence of significant adverse legislative and regulatory changes, in particular changes to the legislation and regulation governing fiscal regimes and environmental issues; and stability of general domestic and global economic, market and business conditions;

- with respect to the Company's Offshore business in Asia Pacific and Atlantic, upstream operations in the Lloydminster Heavy Oil Value Chain, Oil Sands and Western Canada Production: the accuracy of future production rates and reserve estimates; the securing of sales agreements to underpin the commercial development and regulatory approvals for the development of the Company's properties; the absence of significant delays in the procurement, development, construction or commissioning of the Company's projects, for which the Company or a third party is the designated operator, that may result from the inability of suppliers to meet their commitments, lack of regulatory or third-party approvals or other governmental actions, harsh weather or other calamitous event; the absence of significant disruption of operations such as may result from harsh weather, natural disaster, work stoppages related to COVID-19, accident, civil unrest or other calamitous event; the absence of significant unexpected technological or commercial difficulties that adversely affect exploration, development, production, processing or transportation; the sufficiency of budgeted capital expenditures in carrying out planned activities; and the absence of significant increases in the cost of major growth projects; and

- with respect to downstream operations in the Lloydminster Heavy Oil Value Chain, U.S. Refining and Canadian Refined Products: the absence of significant delays in the development, construction or commissioning of the Company's projects that may result from the inability of suppliers to meet their commitments, lack of regulatory or third-party approvals or other governmental actions, harsh weather or other calamitous event; the absence of significant disruption of operations such as may result from harsh weather, natural disaster, work stoppages related to COVID-19, accident, civil unrest or other calamitous event; the absence of significant unexpected technological or commercial difficulties that adversely affect processing or transportation; the sufficiency of budgeted capital expenditures in carrying out planned activities; and the absence of significant increase in the cost of major growth projects.

Because actual results or outcomes could differ materially from those expressed in any forward-looking statements, investors should not place undue reliance on any such forward-looking statements. By their nature, forward-looking statements involve numerous assumptions, inherent risks and uncertainties, both general and specific, which contribute to the possibility that the predicted outcomes will not occur. Some of these risks, uncertainties and other factors are similar to those faced by other oil and gas companies and some are unique to Husky. The risks, uncertainties and other factors, many of which are beyond Husky's control, that could cause actual results to differ (potentially significantly) from those expressed in the forward-looking statements include, but are not limited to:

- with respect to the business, operations and results of the Company generally: those risks, uncertainties and other factors described under "Risk Factors" in this AIF and throughout the Company's MD&A for the year ended December 31, 2020; the extent to which COVID-19 impacts the global economy and harms commodity prices; the extent to which COVID-19 impacts our operations; the demand for the Company's products and prices received for crude oil and conventional natural gas production and refined petroleum products; the economic conditions of the markets in which the Company conducts business; the exchange rate between the Canadian and U.S. dollar; the foreign currency risk relating to gas and liquids sales agreements which are denominated in Chinese Yuan; the ability to replace reserves of oil and gas, whether sourced from exploration, improved recovery or acquisitions; potential actions of governments, regulatory authorities and other stakeholders that may impose operating costs or restrictions in the jurisdictions where the Company has operations; changes to royalty regimes; changes to government fiscal, monetary and other financial policies; changes in workforce demographics; and the cost and availability of capital, including access to capital markets at acceptable rates;

- with respect to the Company's Offshore business in Asia Pacific and Atlantic, upstream operations in the Lloydminster Heavy Oil Value Chain, Oil Sands and Western Canada Production: the availability of prospective drilling rights; the costs to acquire exploration rights, undertake geological studies, appraisal drilling and project development; the availability and cost of labour, technical expertise, material and equipment to efficiently, effectively and safely undertake capital projects; the costs to operate properties, plants and equipment in an efficient, reliable and safe manner; prevailing climatic conditions in the Company's operating locations; regulations to deal with climate change issues; the competitive actions of other companies, including increased competition from other oil and gas companies; business interruptions because of unexpected events such as fires, blowouts, freeze-ups, equipment failures and other similar events affecting the Company or other parties whose operations or assets directly or indirectly affect the Company and that may or may not be financially recoverable; the co-operation of business partners especially where the Company is not operator of production projects or developments in which it has an interest; the inability to obtain regulatory approvals to operate existing properties or develop significant growth projects; risk associated with transportation of production or product to market or transportation of feedstock to processing facilities resulting from an interruption in pipeline and other transportation services both owned and contracted, due to calamitous event or regulatory obligation; and the inability to reach estimated production levels from existing and future oil and gas development projects as a result of technological or commercial difficulties; the continued availability of third-party owned equipment for operations; and

- with respect to downstream operations in the Lloydminster Heavy Oil Value Chain, U.S. Refining and Canadian Refined Product: the costs to operate properties, plants and equipment in an efficient, reliable and safe manner; regulatory (environmental, licence to operate, social and political) and prevailing climatic conditions in the Company's operating locations; regulations to deal with climate change issues; the competitive actions of other companies, including increased competition from other oil and gas companies; business interruptions because of unexpected events such as fires, loss of containment, freeze-ups, equipment failures and other similar events affecting Husky or other parties whose operations or assets directly or indirectly affect the Company and that may or may not be financially recoverable; risk associated with transportation of production or product to market or transportation of feedstock to processing facilities resulting from an interruption in pipeline and other transportation services both owned and contracted, due to calamitous event or regulatory obligation; and the inability to obtain regulatory approvals to operate existing properties or develop significant growth projects.

These and other factors are discussed throughout this AIF and in the MD&A for the year ended December 31, 2020, which is available on SEDAR at www.sedar.com and on EDGAR at www.sec.gov.

In the discussions above, the Company has categorized the material factors and assumptions used to develop the forward-looking statements, and the risks, uncertainties and other factors that could influence actual results, by region, properties, plays and segments. These categories reflect the Company's current views regarding the factors, assumptions, risks and uncertainties most relevant to the particular region, property, play or segment. Other factors, assumptions, risks or uncertainties could impact a particular region, property, play or segment, and a factor, assumption, risk or uncertainty categorized under a particular region, property, play or segment could also influence results with respect to another region, property, play or segment.

New factors emerge from time to time and it is not possible for management to predict all of such factors and to assess in advance the impact of each such factor on the Company's business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are dependent upon other factors, and the Company's course of action would depend upon management's assessment of the future considering all information available to it at the relevant time. Any forward-looking statement speaks only as of the date on which such statement is made and, except as required by applicable securities laws, the Company undertakes no obligation to update any forward-looking statement to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events.

Non-GAAP Measures

This AIF contains references to the terms "operating netback", "return on capital in use" and "net debt", which do not have standardized meanings prescribed by IFRS and are therefore unlikely to be comparable to similar measures presented by other issuers. None of these measures is used to enhance the Company's reported financial performance or positions. There measures are useful complementary measures in assessing the Company's financial performance, efficiency and liquidity. With the exception of "net debt", there are no comparable measures to these non-GAAP measures under IFRS.

"Operating netback" or "netback" is a common non-GAAP measure used in the oil and gas industry. This measure assists management and investors to evaluate the specific operating performance by product at the oil and gas lease level. Operating netback is calculated as realized price less royalties, operating costs and transportation costs on a per unit basis,

"Return on capital" in use or "ROCIU" is a measure used by the Corporation to gauge the capital productivity of assets currently in production. ROCIU is a non-GAAP measure used to assist in analyzing shareholder value and return on capital. ROCIU equals net earnings plus after tax interest expense divided by the two-year average capital employed, less any capital invested in assets that are not in use.

"Net debt" is a non-GAAP measure that equals the sum of long-term debt, long-term debt due within one year and short-term debt, less cash and cash equivalents. Net debt is considered to be a useful measure in assisting management and investors to evaluate the Company's financial strength.

Net Debt *($ millions)*	**December 31, 2020**
Short-term debt	**40**
Long-term debt due within one year	**—**
Long-term debt	**6,117**
Total debt	**6,157**
Cash and cash equivalents	**(735)**
Net debt	**5,422**

Disclosure of Oil and Gas Information

Unless otherwise indicated: (i) reserves estimates have been prepared by internal qualified reserves evaluators in accordance with the Canadian Oil and Gas Evaluation Handbook, has been audited and reviewed by Sproule, an independent qualified reserves auditor, have an effective date of December 31, 2020 and represent the Company's working interest share (ii) projected and historical production volumes quoted are gross, which represents the total or the Company's working interest, as applicable share before deduction of royalties (iii) all Husky working interest production volumes quoted are before deduction of royalties; and (iv) historical production volumes provided are for the year ended December 31, 2020.

The Company uses the term "barrels of oil equivalent" (or "boe"), which is consistent with other oil and gas companies' disclosures, and is calculated on an energy equivalence basis applicable at the burner tip whereby one barrel of crude oil is equivalent to six thousand cubic feet of conventional natural gas. The term boe is used to express the sum of the total company products in one unit that can be used for comparisons. Readers are cautioned that the term boe may be misleading, particularly if used in isolation. This measure is used for consistency with other oil and gas companies and does not represent value equivalency at the wellhead.

The Company uses the term reserves replacement ratio, which is consistent with other oil and gas companies' disclosures. Reserves replacement ratios for a given period are determined by taking the Company's proved reserve changes for that period divided by the Company's upstream gross production for the same period. Reserves changes include: revisions, purchases, sales, improved recovery, discoveries and extensions. The reserves replacement ratio measures the amount of reserves changes to a company's reserves base during a given period relative to the amount of oil and gas produced during that same period. A company's reserves replacement ratio must be at least 100% for the company to maintain its reserves. Reserves replacement ratios that exclude economic factors will exclude the impacts that changing oil and gas prices, inflation, and exchange rates and the regulatory curtailment imposed by the Alberta government have.

Note to U.S. Readers

The Company reports its reserves and resources information in accordance with Canadian practices and specifically in accordance with NI 51-101, adopted by the Canadian securities regulators. Because the Company is permitted to prepare its reserves and resources information in accordance with Canadian disclosure requirements, it may use certain terms in that disclosure that U.S. oil and gas companies generally do not include or may be prohibited from including in their filings with the SEC.

All currency is expressed in Canadian dollars unless otherwise directed.

Husky Energy Inc.

Report on Reserves Data by Independent Qualified Reserves Auditors

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

(1) We have audited or reviewed the Company's reserves data as at December 31, 2020. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2020, 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 audit and review.

(3) We carried out our audit and review 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 audit and review to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An audit and review also includes assessing whether the reserves data are in accordance with the 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%, included in the reserves data of the Company audited and reviewed for the year ended December 31, 2020, and identifies the respective portions thereof that we have audited and reviewed and reported on to the Company's management and board of directors.

Independent Qualified Reserves Evaluator or Auditor	Effective Date	Location of Reserves (Country)	Net Present Value of Future Net Revenue (Before Income Taxes,10% Discount Rate)			
			Audited (MM$)	Evaluated (MM$)	Reviewed (MM$)	Total (MM$)[2]
Sproule Associates Limited	December 31, 2020	Canada	7,551.4	Nil	(1,347.4)[1]	6,204.0
		China	3,943.8	Nil	—	3,943.8
		Indonesia	561.1	Nil	—	561.1
Total			**12,056.3**	**Nil**	**(1,347.4)[1]**	**10,708.8**

[1] Negative NPV10 results from inclusion of Canadian Abandonment and Reclamation costs plus suspended well operating costs for all existing assets
[2] Numbers may not add due to rounding

(6) In our opinion, the reserves data audited 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 report referred to in paragraph 5 for events and circumstances occurring after the effective date of our report.

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

Sproule Associates Limited
Calgary, Alberta
January 25, 2021

/s/ Cameron P. Six, P. Eng.
Cameron P. Six, P. Eng.
Sr. Petroleum Engineer

/s/ Alec Kovaltchouk, P. Geo.
Alec Kovaltchouk, P. Geo.
VP, Geoscience

Husky Energy Inc.

Report of Management and Directors on Oil and Gas Disclosure

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

An independent qualified reserves auditor has audited and reviewed the Company's reserves data. The report of the independent qualified reserves auditor 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 auditor;

b. met with the independent qualified reserves auditor to determine whether any restrictions affected the ability of the independent qualified reserves auditor to report without reservation; and

c. reviewed the reserves data with management and the independent qualified reserves auditor.

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 auditor 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.

/s/ Jeffrey R. Hart — February 8, 2021

Jeffrey R. Hart Acting Chief Executive Officer & Chief Financial Officer

/s/ Andrew Dahlin — February 8, 2021

Andrew Dahlin
Acting Chief Operating Officer

/s/ Frank J. Sixt — February 8, 2021

Frank J. Sixt
Director

/s/ Wayne E. Shaw — February 8, 2021

Wayne E. Shaw
Director

Husky Energy Inc.

Independent Qualified Reserves Auditor Audit Opinion

Husky Energy Inc.
707 - 8th Avenue S.W.
Calgary, Alberta
T2P 3G7

Attention: Ms. Nicole Labrecque, Director, Reserves

Re: Audit of Husky Energy Inc.'s 2020 Year-End Reserves

As requested by Husky Energy Inc. ("Husky" or the "Company"), Sproule has conducted an audit of Husky's reserves estimates and the respective net present values as at December 31, 2020. Husky internally evaluates all of their properties. Husky's detailed reserves information was provided to us for this audit. Sproule's responsibility is to express an independent opinion on the reasonableness of the reserves estimates and the respective net present value estimates, in the aggregate, based on our audit tests and to assess the quality of the Company's processes and guidelines applied in the preparation of the reserves information.

We conducted our audit in accordance with generally accepted audit standards as recommended by the Society of Petroleum Engineers and the Canadian Oil and Gas Evaluation Handbook (section 5.3.3 of the Third Edition). As part of our audit, Sproule reviewed and assessed the policies, procedures, documentation and guidelines the Company has in place with respect to the estimation, review, documentation, and approval of Husky's reserves information. The audit included confirming on a test basis that there is adherence on the part of Husky's internal reserve evaluators and other employees to the reserves management and administration policies and procedures established by the Company. As well, the audit also included conducting reserves evaluation on a sufficient number of the Company's internally evaluated properties as considered necessary in order to express an opinion.

For the 2020 year-end audit Sproule also reviewed the internal Husky reserve evaluation for all of the intermediate and minor properties that were not audited. Thus, for the 2020 year-end Sproule has either audited or reviewed every Husky property that was assigned reserves.

Based on the results of our audit, it is our opinion that Husky's internally generated proved and probable reserves and net present values based on forecast and constant price assumptions are, in aggregate, reasonable, and have been prepared in accordance with generally accepted oil and gas engineering and evaluation practices as set out in the COGE Handbook.

The results of the Husky internally generated reserves and net present values (based on forecast prices) supplied to us as part of the audit process are summarized below:

Husky Energy Inc. Internally Evaluated Reserves and Net Present Values Forecast Prices and Costs As of December 31, 2020		
	Working Interest Before Royalty Company Share of Remaining Reserves (mmboe)	Company Share of Net Present Value Before Income Tax (MM$) @ 10%
Total Proved	1,241	6,753
Total Proved Plus Probable	1,753	10,709

Sincerely,

Sproule Associates Limited

/s/ Cameron P. Six, P. Eng.
Cameron P. Six, P. Eng.
Sr. Petroleum Engineer
Calgary, Alberta
January 23, 2021