Husky Energy

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2018

February 26, 2019

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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, 2018, 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.

See also "Reader Advisories" on page 81 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	barrels
bbls/day	barrels per calendar day
bcf	billion cubic feet
boe	barrels of oil equivalent
boe/day	barrels of oil equivalent per calendar day
CO_2e	carbon dioxide equivalent
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
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
tCO_2e	tonnes of carbon dioxide equivalent

abandonment and reclamation costs
All costs associated with the process of restoring Husky'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.

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.

Atlantic Accord
The memorandum of agreement between the Government of Canada and the Government of the Province of Newfoundland and Labrador on offshore petroleum resource management and revenue sharing dated February 11, 1985, including any amendments to the memorandum of agreement.

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

bitumen

Bitumen is 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 or Board of Directors

The board of directors of the Company.

BP-Husky Toledo Refinery

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

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 oil, added to heavy oil and bitumen to facilitate the transmissibility of the oil through a pipeline.

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

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.

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.

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.

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 mixture consisting primarily of methane, but commonly including varying amounts of other higher alkanes, and sometimes a small percentage of carbon dioxide, nitrogen and/or hydrogen sulfide.

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.

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

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.

Plan of Development
As it relates to the Company's operations in Indonesia, a Plan of Development represents development planning on one or more oil and gas fields in an integrated and optimal plan for the production of hydrocarbon reserves considering technical, economical and environmental aspects. An initial Plan of Development in a development area needs both SKK Migas and the Minister of Energy and Mineral Resources approvals. Subsequent Plans of Development in the same development area only need SKK Migas approval.

Prince George Refinery
The light oil refinery owned by the Company and located in Prince George, British Columbia.

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

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

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 or SDL
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 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.

turnaround
Performance of plant or facility maintenance.

unproved property
Property or part of a party to which no reserves have been specifically attributed.

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.

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$)*	**2018**	2017	2016
Year-end(1)	**1.365**	1.252	1.343
Low	**1.228**	1.213	1.254
High	**1.365**	1.374	1.459
Average	**1.296**	1.298	1.325

(1) The year-end exchange rates for 2018 and 2017 were as quoted by the Thomson Reuters WM/R for the noon rate at the last day of the relevant period. The year-end exchange rate for 2016 was as quoted by the Bank of Canada for the noon buying rate as at the last day of the relevant period. The Bank of Canada discontinued the publication of the noon buying rates during 2017. The high, low and average rates were either quoted by Thomson Reuters WM/R or the Bank of Canada, as applicable, or calculated from data from those sources within each of the relevant periods.

CORPORATE STRUCTURE

Incorporation and Organization

Husky Energy Inc. was incorporated under the *Business Corporations Act* (Alberta) 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, 2018. All of the entities listed below, except as otherwise indicated, are 100 percent 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 Terra Nova Partnership	Alberta
Husky Downstream General Partnership	Alberta
Husky Energy Marketing Partnership	Alberta
Sunrise Oil Sands Partnership (50 percent)	Alberta
BP-Husky Refining LLC (50 percent)	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.

2016

On March 9, 2016, the maturity date for one of the Company's $2.0 billion revolving syndicated credit facilities, previously set to expire on December 14, 2016, was extended to March 9, 2020. In addition, the Company's leverage covenant was modified to a debt-to-capital covenant.

On March 31, 2016, the Company announced that holders of 1,564,068 Series 1 Preferred Shares exercised their option to convert their shares, on a one-for-one basis, to Series 2 Preferred Shares and receive a floating rate quarterly dividend.

On April 18, 2016, the Company announced that it had commenced production at the 10,000 bbls/day Edam East Thermal Project in Saskatchewan.

On April 19, 2016, the Company commenced production from the Colony formation at the Tucker Thermal Project in the Cold Lake region of Alberta.

On May 25, 2016, the Company completed the sale of Western Canada royalty interests to a third party for gross proceeds of $165 million.

On June 16, 2016, the Company announced that it had commenced production at the 10,000 bbls/day Vawn Thermal Project in Saskatchewan.

Production from the Sunrise Energy Project was temporarily impacted by wildfires in the Fort McMurray region of Alberta in the second quarter of 2016. Operations were successfully restarted in the same quarter with all 55 well pairs back online and the plant being fully operational.

On July 15, 2016, the Company completed the sale of 65 percent of its ownership interest in select midstream assets in the Lloydminster region of Alberta and Saskatchewan for gross proceeds of $1.69 billion in cash. The assets included approximately 1,900 kilometres of pipeline in the Lloydminster region, 4.1 mmbbls of storage capacity at Hardisty and Lloydminster and other ancillary assets. The assets were sold to Husky Midstream Limited Partnership ("HMLP"), of which Husky owns 35 percent, Power Assets Holdings Limited ("PAH") owns 48.75 percent and CK Infrastructure Holdings Limited ("CKI") owns 16.25 percent. Proceeds from the transaction were received in the third quarter of 2016.

On August 2, 2016, the Company announced that its China subsidiary had signed a Heads of Agreement ("HOA") with China National Offshore Oil Corporation ("CNOOC") and relevant companies for the price adjustment of natural gas from the Liwan 3-1 and Liuhua 34-2 fields with the revised price set at Cdn$12.50-Cdn$15.00 per mcf. The price adjustment under the HOA was effective as of November 20, 2015, and the settlement of outstanding payment was calculated from that date.

On August 29, 2016, the Company commenced production at the 4,500 bbls/day Edam West Thermal Project in Saskatchewan.

On September 15, 2016, the Company commenced production at the North Amethyst Hibernia formation well offshore Newfoundland and Labrador ("NL").

On November 9, 2016, the Canada-Newfoundland and Labrador Offshore Petroleum Board ("C-NLOPB") announced that the Company was the successful bidder on two parcels of land in its 2016 land sale. The lands cover an area of 211,574 hectares and brought the Company's exploration licences ("ELs") in the region to eight. The southwest parcel is adjacent to the White Rose field and satellite extensions, while the other is northeast of the field and adjacent to other Husky operated ELs in the Jeanne d'Arc Basin.

On November 29, 2016, the Company commenced production from a third well at the South White Rose project in the Jeanne d'Arc Basin offshore NL.

In late 2016, the Company sanctioned three new Lloyd thermal projects with total design capacity of 30,000 bbls/day at Dee Valley, Spruce Lake North and Spruce Lake Central.

Also during 2016, the Company completed the sale of approximately 30,200 boe/day of legacy crude oil and gas assets in Western Canada for gross proceeds of $1.12 billion.

2017

On March 10, 2017, the Company issued $750 million of 3.60 percent notes due March 10, 2027 by way of a prospectus supplement dated March 7, 2017, to its base shelf prospectus. The notes are redeemable at the option of the Company at any time, subject to a make whole premium unless the notes are redeemed in the three-month period prior to maturity. Interest is payable semi-annually on March 10 and September 10 of each year, beginning September 10, 2017. The notes are unsecured and unsubordinated and rank equally with all of the Company's other unsecured and unsubordinated indebtedness.

On April 13, 2017, the Company announced that it had signed a production sharing contract ("PSC") for Block 16/25 in the Pearl River Mouth Basin in the South China Sea. Under the PSC, Husky has an obligation to drill two exploration wells within the first three years.

On May 5, 2017, the Company announced that, during the first quarter of 2017, it had commenced production from a new eight-well pad at the Tucker Thermal Project in the Cold Lake region of Alberta and from a new infill well at North Amethyst offshore NL.

On May 29, 2017, the Company announced that, together with its partners, it would be moving forward with the West White Rose Project in the Jeanne d'Arc Basin offshore NL, using a fixed wellhead platform tied back to the *SeaRose* FPSO.

Also in May 2017, the Company announced a new discovery at Northwest White Rose. The White Rose A-78 well was drilled approximately 11 kilometres northwest of the *SeaRose* FPSO in the first quarter of 2017 and delineated a light oil column of more than 100 metres (gross). The Company has a 93.23 percent working interest in the well.

On July 21, 2017, the Company announced that the construction and installation of the shallow water jackets and subsea pipelines for the MDA-MBH fields in the Madura Strait were completed. The contract for a leased floating production unit was signed, and planning for the build commenced.

On September 15, 2017, the Company repaid the maturing 6.20 percent notes issued under a trust indenture dated September 11, 2007. The amount paid to note holders was $365 million, including $11 million of interest.

On October 26, 2017, the Company announced that, during the third quarter of 2017, gas production from the BD Project commenced and was sold from the onshore gas distribution facility in East Java under a fixed price gas sales agreement ("GSA").

Also in October 2017, the Company announced that the GSA for future gas production from Liuhua 29-1, the third deepwater gas field at the Liwan Gas Project, was signed. The project was sanctioned in the fourth quarter of 2017.

On November 8, 2017, the Company completed the purchase of the Superior Refinery, a 50,000 bbls/day permitted capacity facility located in Superior, Wisconsin, U.S., from Calumet Specialty Products Partners, L.P. ("Calumet") for $670 million (US$527 million). The acquisition included the Superior Refinery's associated logistics assets, including two asphalt terminals, 3.6 mmbbls of crude and product storage and a fuels and asphalt marketing business. See "Description of Husky's Business – Downstream Operations – U.S. Refining and Marketing – Superior Refinery".

In November 2017, the Company sanctioned two new 10,000 bbls/day thermal projects at Westhazel and Edam Central.

In November 2017, the C-NLOPB announced that the Company was the successful bidder on a parcel of land in its 2017 land sale (50 percent Husky working interest). The lands cover an area of 121,453 hectares in the Jeanne d'Arc Basin. The lands are adjacent to the Company's other ELs in the basin.

Also in November 2017, the Company's participation in the Wenchang oilfields petroleum contract expired, and the Company will not be entitled to any further production rights.

During 2017, the Company completed the sale of select assets in Western Canada, representing approximately 20,200 boe/day for gross proceeds of approximately $185 million.

Also during 2017, regulatory approval was received for the three Lloyd thermal projects sanctioned in late 2016, Dee Valley, Spruce Lake North and Spruce Lake Central.

Also during 2017, the Company and Imperial Oil closed their previously announced transaction to create a single expanded truck transport network of approximately 160 sites.

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 that the Board of Directors had approved 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. Normal operations are not expected to resume until 2020.

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 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"). The offer expired on January 16, 2019 without the minimum tender condition satisfied and the offer was not extended.

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

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. Operations resumed in the first quarter of 2019.

In November 2018, Spruce Lake East was sanctioned, with regulatory approval received in 2019.

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

Recent Developments

On January 8, 2019, the Company announced its intention to market and potentially sell its Prince George Refinery and Retail and Commercial Network.

DESCRIPTION OF HUSKY'S BUSINESS

Overview

Husky is a publicly traded international integrated energy company headquartered in Calgary, Alberta, Canada.

Management has identified segments for the Company's business based on differences in products, services and management responsibility. The Company's business is conducted predominantly through two major business segments: Upstream and Downstream.

Upstream operations include exploration for, and development and production of, crude oil, bitumen, natural gas and NGL ("Exploration and Production") and the marketing of the Company's and other producers' crude oil, natural gas, NGL, sulphur and petroleum coke. Additionally, it includes pipeline transportation, the blending of crude oil and natural gas, and storage of crude oil, diluent and natural gas ("Infrastructure and Marketing"). Infrastructure and Marketing markets and distributes products to customers on behalf of Exploration and Production and is grouped in the Upstream business segment based on the nature of its interconnected operations. The Company's Upstream operations are located primarily in western Canada, offshore the east coast of Canada ("Atlantic") and offshore China and Indonesia ("Asia Pacific") (Atlantic and Asia Pacific collectively, "Offshore").

Downstream operations in Canada include upgrading of heavy crude oil feedstock into synthetic crude oil ("Upgrading"), refining crude oil, marketing of refined petroleum products including gasoline, diesel, ethanol blended fuels, asphalt and ancillary products, and production of ethanol ("Canadian Refined Products"). It also includes refining of crude oil in the U.S. to produce and market diesel fuels, gasoline, jet fuel and asphalt ("U.S. Refining and Marketing"). Upgrading, Canadian Refined Products and U.S. Refining and Marketing all process and refine natural resources into marketable products and are grouped together as the Downstream business segment due to the similar nature of their products and services.

Corporate Strategy

The Company's business strategy is to focus on returns from investment in a deep portfolio of opportunities that can generate increased cash flow from operating activities and funds from operations.

The Company has two main businesses: (i) an integrated Canada-U.S. Upstream and Downstream corridor ("Integrated Corridor"); and (ii) production located Offshore.

Integrated Corridor

The Company's business in the Integrated Corridor includes crude oil, bitumen, natural gas and NGL production from Western Canada, the Lloydminster upgrading and asphalt refining complex, HMLP (35 percent working interest and operatorship), and the Lima Refinery, BP-Husky Toledo Refinery (50 percent working interest) and Superior Refinery in the U.S. midwest. Natural gas production from the Western Canada portfolio is closely aligned with the Company's energy requirements for refining and thermal bitumen production and acts as a natural hedge.

Offshore

The Company's Offshore business includes operations, development and exploration in Atlantic and Asia Pacific. Each area generates high-netback production, with near and long-term investment potential.

Upstream Operations

Integrated Corridor

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 percent 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 Husky Lloydminster Asphalt Refinery, the Upgrader and the Company's other assets in its Upstream Infrastructure and Marketing and its Downstream business segments, thus providing full integration.

Production of heavy crude oil and bitumen from the Lloydminister area uses a variety of technologies, including thermal SAGD, cold heavy oil production with sand ("CHOPS"), horizontal wells, waterflooded fields and non-thermal enhanced oil recovery ("EOR").

Lloydminster Thermal Projects

Lloydminster bitumen production consists of 10 thermal plants located in the Lloydminster region of Saskatchewan: Bolney/Celtic, Edam East, Edam West, Paradise Hill, Pikes Peak, Pikes Peak South, Rush Lake 1 & 2, Sandall and Vawn. Each plant has a number of production pads and utilizes SAGD technology. Production in 2018 from Lloydminster thermal projects averaged 76,800 bbls/day.

The Company is phasing execution of its long-life thermal projects to optimize capital efficiency and project execution. In 2018, the Company completed two land deals to create two Thermal hubs, one at Spruce Lake, and one at Dee Valley. This has resulted in the expectation that the Edam Central project will be completed in 2022 rather than the previously disclosed timeframe of late 2021, and in Westhazel being reprioritized.

The following table shows major projects and their status as at December 31, 2018:

Project Name	Estimated Production (bbls/day)	Expected Project Production Date	Project Status
Rush Lake 2	10,000	First quarter of 2019	Completed ahead of schedule with first production achieved in October 2018 and nameplate capacity of 10,000 bbls/day reached in November 2018.
Dee Valley	10,000	Fourth quarter of 2019	Work continued, with drilling of the second well pad completed and construction of the Central Processing Facility ("CPF") continuing ahead of schedule. As of the end of 2018, the CPF was 80 percent complete.
Spruce Lake Central	10,000	2020	Construction of the CPF commenced in 2018.
Spruce Lake North	10,000	Around the end of 2020	Site clearing was completed in 2018.
Spruce Lake East	10,000	Around the end of 2021	Sanctioned in November 2018, with regulatory approval received in 2019. Prioritized ahead of Westhazel.
Edam Central	10,000	2022	Regulatory permit was received in early January 2019.
Dee Valley 2	10,000	2023	Regulatory applications were submitted in 2018, with approval expected in 2019.
Westhazel	10,000	Reprioritized	Regulatory applications were submitted in 2018, with approval expected in 2019. Reprioritized in order to optimize thermal sequence.

In February 2019, the Pike's Peak thermal bitumen plant was closed down as it reached the end of its useful life. The plant achieved first production in September 1981 and produced 78 mmbbls over its useful life.

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.

Work to debottleneck the CPF and field was completed in the third quarter of 2018. Subsequently, production ramped up and nameplate capacity of 30,000 bbls/day was achieved in October 2018. Bitumen production for 2018 averaged 22,400 bbls/day, with fourth quarter production following the debottleneck averaging 25,200 bbls/day.

Production in 2019 is expected to be impacted by government-mandated production curtailment in Alberta. While specific volume reductions are uncertain, production in the first quarter of 2019 could be impacted by as much as 5,000 bbls/day.

Cold and EOR

In 2018, the Company sanctioned a full field polymer injection project at Aberfeldy with opportunities to expand to other areas.

During 2018, the Company operated five carbon dioxide ("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 several types of CO_2 capture technology at its Lashburn facility in Saskatchewan.

Production in 2019 is expected to be impacted by government-mandated production curtailment in Alberta.

Sunrise Energy Project
On March 31, 2008, Husky and BP Corporation North America Inc. ("BP") 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.

The Sunrise Energy Project is a SAGD oil sands project located in the Athabasca region of northern Alberta. During the fourth quarter of 2018, maintenance activities were completed and the project reached its nameplate capacity of 60,000 bbls/day.

At the end of 2018, there were 81 producing well pairs. In 2018, bitumen production averaged approximately 50,000 bbls/day (25,000 bbls/day Husky working interest).

Production in 2019 is expected to be impacted by government-mandated production curtailment in Alberta. While specific volume reductions are uncertain, production in the first quarter of 2019 could be impacted by as much as 15,000 bbls/day (7,500 bbls/day Husky working interest).

Western Canada

Northern Operations
The Company's Northern operations are located primarily in western Alberta. Primary areas of operations include Edson and Grande Prairie, where operations are centered on a liquids-rich gas resource growth strategy.

Within its Northern operations, production in 2018 consisted of approximately 1,300 bbls/day of light crude oil, 4,800 bbls/day of NGL and 179.6 mmcf/day of natural gas. The area is heavily weighted towards natural gas production at approximately 84 percent. The Company is pursuing liquids-rich natural gas development opportunities within the existing asset portfolio primarily in the Ansell and Kakwa areas.

The Kakwa Spirit River liquids-rich natural gas resource play, in which 2018 production averaged 5,900 boe/day, is located south of Grande Prairie. The Company drilled 10 wells in 2018, and completed nine wells with eight wells on production by the end of 2018.

Edson operations are located primarily in northern Alberta and consist of the Ansell and Galloway areas. The Ansell liquids-rich natural gas resource play is located in the deep basin Cretaceous formations of west-central Alberta, with the Company holding an average 95 percent 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 2018 averaged 2,300 bbls/day of NGL and 131.8 mmcf/day of natural gas. The Company operates over 400 producing wells at Ansell including 65 Spirit River horizontal wells and 20 Cardium horizontal wells. In 2018, the Company drilled 11 horizontal wells and completed 13 horizontal wells with 11 wells on production at the end of 2018. The Company also participated in three non-operated wells.

A drilling program targeting the oil and liquids-rich natural gas Montney Formation in the Wembley and Karr areas is continuing with seven wells drilled in 2018 and six completed.

Resource oil development is focused on the Cardium oil play in the Wapiti area south of the city of Grand Prairie, Alberta, utilizing horizontal well and multi-stage fracturing technology to unlock crude oil reserves. During 2018, production from the Cardium play averaged 2,500 boe/day. A two well drilling program was completed in 2018 with six wells completed and on production. In addition, the Company participated in two non-operated wells.

In 2018, the Company participated in a 12-well non-operated Viking program in the North Blackstone area, which continued into 2019.

Southern Operations
The Company's Southern operations are located in central Alberta and southwest Saskatchewan. As at December 31, 2018, the Company operated one crude oil and four natural gas facilities with approximately 400 active wells throughout the area. Production in 2018 averaged 1,000 bbls/day of crude oil, 2,000 bbls/day of NGL and 36.7 mmcf/day of natural gas.

Rainbow Lake Development
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 2018 from the Rainbow Lake Development operations averaged 5,200 bbls/day of light crude oil, 5,200 bbls/day of NGL and 55.1 mmcf/day of natural gas. The Company initiated an 11-well Muskeg oil appraisal program in 2018 with four wells on production at year end.

The Company holds a 50 percent 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 exploration licenses ("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. Summer work in 2018 in the Slater River area included annual inspections of the two suspended wells and maintenance on the existing infrastructure. In the fourth quarter of 2018, the Company commenced operations that included abandonment of the two pilot wells, reclamation of the well sites, and remediation and maintenance of infrastructure. This program will continue into 2019.

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 percent working interest in the Liwan 3-1 and Liuhua 34-2 fields and a 75 percent working interest in the Liuhua 29-1 field, and CNOOC has 51 and 25 percent 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 deepwater operator and CNOOC acting as shallow water operator. The deepwater infrastructure includes production wells and trees, subsea pipelines and manifolds that produce to twin 22-inch deepwater pipelines running approximately 78 kilometres to a shallow water central platform. The shallow water infrastructure includes the central platform standing in approximately 120 metres of water, a 261-kilometre shallow water pipeline running from the central platform to the onshore Gaolan Gas Plant, which has liquids separation facilities, 10 spherical NGL storage tanks, an export jetty, control facilities 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.

In 2018, total gas sales from Liwan 3-1 and Liuhua 34-2 averaged 341 mmcf/day and 36 mmcf/day, respectively. In 2018, the Company's working interest share of production from the two fields was 185 mmcf/day of conventional natural gas and 8,400 bbls/day of NGL.

Construction continues at Liuhua 29-1, the third deepwater gas field of the Liwan Gas Project. All of the major contracts have been executed and detailed design work is underway. The Environment Impact Assessment was approved by the Ministry of Ecology and Environment in January 2019. Drilling of the remaining three wells is expected to commence in the first quarter of 2019, which will add to the four previously drilled wells. First gas production from this seven-well development is expected around the end of 2020, with target production of 45 mmcf/day natural gas (Husky working interest) and 1,800 bbls/day NGL (Husky working interest) when fully ramped up.

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 percent. In the event of a commercial discovery, its partner CNOOC may assume a working interest of up to 51 percent during the development and production phase. Under the PSC, the corresponding CNOOC share of exploration costs is to be recovered from production allocated to the Company.

The Company is progressing commercial development plans following the successful drilling and testing of exploration well XJ 34-3-2.

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 to100 metres. The Company is the operator of the block during the exploration phase, with a working interest of 100 percent. In the event of a commercial discovery, its partner CNOOC may assume a working interest of up to 51 percent during the development and production phase. Under the PSC, the corresponding CNOOC share of exploration costs is to be recovered from production allocated to the Company.

The Company drilled one exploration well in the third quarter of 2018, which encountered non-commercial hydrocarbons. Additional evaluation work is being conducted and a second exploration well may be drilled in the 2020 timeframe.

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 percent during the exploration phase. In the event of a commercial discovery, its partner CNOOC may assume a participating partnership interest of up to 51 percent in either or both blocks for the development and production phases.

Taiwan

In December 2012, the Company signed a joint venture agreement with CPC Corporation. 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 percent working interest during exploration, while CPC Corporation has the right to participate in the development program up to a 50 percent 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. The Company is analyzing the 3-D seismic survey data to identify potential drilling prospects.

Indonesia

Madura Strait

The Company has a 40 percent interest in approximately 622,000 acres (2,516 square kilometres) of the Madura Strait, located offshore East Java, in Indonesia. The Company's two partners are CNOOC, which is the operator and has a 40 percent 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 developments at the MDA, MBH, MDK and MAC fields and three additional discoveries.

In 2018 at the liquids-rich BD field, total gas sales ramped up to the full sales production target of 100 mmcf/day of gas and 6,000 bbls/day of associated liquids. Total BD field sales averaged 78 mmcf/day of gas and 6,200 bbls/day of associated liquids in 2018. The Company's working interest share of production was 31 mmcf/day of gas and 2,500 bbls/day of associated liquids.

At the MDA and MBH fields, the two shallow water platforms have been fully installed and preparations are underway to drill the five MDA and two MBH field production wells in 2019. Gas production and sales are expected to start in the 2020 timeframe, following completion of the Floating Production Unit ("FPU") which will be used to process and compress the gas. Subsequently, an additional shallow water field, named MDK, is scheduled to be developed and tied into the FPU. 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 with set prices that include escalation factors.

Pre-engineering activities and approvals progressed at the MAC field, where an approved Plan of Development is in place. Additional discoveries in the region are being evaluated for potential development.

Anugerah

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

During 2015, the Company acquired 2-D seismic survey 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 offset block information indicates that drilling is not economic and the block will be relinquished.

Atlantic

Overview

The Company's Atlantic exploration and development program is focused in the Jeanne d'Arc Basin and the Flemish Pass. 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 percent 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 percent working interest in the main field and a 68.875 percent 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 11 production wells, 10 water injection wells and three gas injection wells. During 2018, the Company's light crude oil production from the White Rose field was 6,400 bbls/day (Husky working interest).

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. In September 2016, the Company began production from the deeper Hibernia formation at North Amethyst utilizing existing infrastructure. As of December 31, 2018, the field had eight production wells and four water injection wells. During 2018, light crude oil production from North Amethyst was 3,400 bbls/day (Husky working interest).

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 2018, light crude oil production from this satellite field was 800 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. The South White Rose Extension was developed in phases, with gas injection equipment installed in 2013 and oil production equipment installed in 2014. As at December 31, 2018, the project had three production wells, one water injection well and one gas injection well. During 2018, light crude oil production from the South White Rose Extension was 6,800 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. First oil is forecasted for 2022, with the West White Rose Project expected to ramp up to peak production of 52,500 bbls/day (Husky working interest) in 2025 as development wells are brought online. Like the other White Rose tiebacks, the platform will leverage existing offshore infrastructure including the *SeaRose* FPSO. 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. The accommodations module is progressing well in Marystown, NL and construction of the platform's Concrete Gravity Structure ("CGS") advanced in a purpose-built graving dock in Argentia, NL. The CGS was poured to a height of 46 metres during the 2018 construction season. Concrete works will continue in 2019.

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.

In late January 2019, the Company began a staged ramp-up production at the White Rose field. The field had been shut-in since mid-November, after a flowline connector failed near the South White Rose Extension, causing a spill of approximately 250 cubic metres of oil. The Company and its certifying authority have completed inspections of the *SeaRose* FPSO vessel as well as subsea infrastructure. Regulatory approval has been received for plans to recover the damaged flowline connector. An investigation into the cause of the incident is underway.

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 percent effective December 1, 2010.

As at December 31, 2018, there were 14 development wells drilled in the Graben area, consisting of eight 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. The operator continues to progress delineation and development opportunities at Terra Nova.

Light crude oil production during 2018 from the Terra Nova field was 4,000 bbls/day (Husky working interest).

East Coast Exploration
The Company holds working interests ranging from 5.8 percent to 100 percent in 22 Significant Discovery Areas in the Jeanne d'Arc Basin and Flemish Pass Basin, offshore NL and Baffin Island.

In May 2018, the Company announced a near-field oil discovery at the White Rose A-24 exploration well, located approximately 10 kilometres north of the *SeaRose* FPSO. The well encountered more than 85 metres of oil-bearing sandstone. Additional delineation in the region is planned. The Company has a 68.875 percent ownership interest, with partners Suncor Energy and Nalcor Energy Oil and Gas holding 26.125 percent and five percent, respectively.

The Company continues to evaluate the results of a 2017 discovery at Northwest White Rose. The White Rose A-78 well was drilled approximately 11 kilometres northwest of the *SeaRose* FPSO in the first quarter of 2017 and delineated a light oil column of more than 100 metres. Husky has a 93.232 percent ownership interest.

Potential development of the A-24 and A-78 regions could leverage the *SeaRose* FPSO, existing subsea infrastructure and the future West White Rose platform.

The Company and its partner continue to assess potential development of Bay du Nord and other discoveries in the Flemish Pass Basin. A benefits framework agreement was reached with the Government of Newfoundland and Labrador in July 2018, based on an FPSO-based development concept to produce resources at Bay du Nord and Bay de Verde. Technological and commercial evaluations continue. The Company holds a 35 percent non-operated working interest in the Bay du Nord, Bay de Verde, Baccalieu, Harpoon and Mizzen discoveries.

The Company is a non-operating partner in two ELs awarded in the November 2018 C-NLOPB land sale. The ELs are adjacent to Terra Nova and White Rose in the Jeanne d'Arc Basin and will bring the Company's total licence holdings in the region to nine.

Infrastructure and Marketing

Overview
The Company is engaged in the marketing of both its own and other producers' crude oil, natural gas, NGL, sulphur and petroleum coke production. The Infrastructure and Marketing business manages the sale and transportation of the Company's Upstream and Downstream production and third-party commodity trading volumes through access to capacity on third-party pipelines and storage facilities in both Canada and the U.S. The Company is able to capture 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.

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 owns 16.25 percent, PAH owns 48.75 percent and Husky owns 35 percent of HMLP and is the operator. HMLP has approximately 2,200 kilometres of pipeline in the Lloydminster region, 4.1 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 Husky's Upgrader and Asphalt Refinery in Lloydminster. 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 3.4 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 a separate Board of Directors from Husky and independent financing that supports both significant growth projects that are under construction and forecasted future expansions. Approximately $800 million in growth projects are underway. HMLP is in the process of diversifying its operations beyond the Lloydminster and Hardisty area and has commenced construction of the Ansell Corser Gas Plant, which is expected to add 120 mmcf/day of processing capacity when it comes online in the fourth quarter of 2019.

In 2018, HMLP commissioned a 150-kilometre pipeline system in Alberta to allow for third-party and Husky production growth. A second major pipeline project is underway in Saskatchewan to provide transportation for the anticipated increase in the Company's bitumen production. The Hardisty terminal is also expanding to provide additional pipeline connectivity and crude oil storage for customers. The assets will play an integral and valuable role in the successful transportation of heavy oil and bitumen production to end markets by providing connections to the Husky Lloydminster Upgrader and Asphalt Refinery, third-party terminals and pipelines through strategic hubs such as the Hardisty Terminal.

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 midwest U.S. This strategy was further supported through the acquisition of the Lima Refinery in 2007, which enabled the Company's Canadian synthetic 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 bitumen 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 bbls/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.

The Company has been monitoring opportunities to participate in growing crude oil markets accessed by rail, which have developed due to refiners' desire for inland crude oil which has at times been priced at significant discounts to ocean imports. The Company has made crude oil deliveries to rail-loading facilities via trucks, where netbacks can be increased relative to pipeline alternatives. While the Company's primary focus is on low-cost pipeline transportation options, it has developed the capability to employ rail transport to a variety of crude oil markets.

In December of 2018, the Government of Alberta imposed an oil production curtailment order with the goal of raising the price of oil sold in Alberta during 2019. This reduced the economic motivation to export crude by rail or develop longer term market access strategies.

Natural Gas Storage Facilities

The Company has operated a 25 bcf natural gas storage facility at Hussar, Alberta since 2000.

Commodity Marketing

The Company has developed its commodity marketing operations to include the acquisition of third-party volumes to enhance the value of its midstream 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 and Wisconsin refineries. The Company supplies feedstock to its Lloydminster 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 Prince George Refinery, the Lima Refinery and the Superior Refinery. The Company supplies a portion of the synthetic crude oil produced at its Upgrader in Lloydminster to the Lima and Superior refineries, 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.

Downstream Operations

Upgrading Operations

The Company owns and operates the Upgrader, a heavy oil upgrading facility located in Lloydminster, Saskatchewan. 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 recover 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 80,500 bbls/day of synthetic crude oil, diluent and ultra low sulphur diesel.

Production at the Upgrader averaged 53,800 bbls/day of synthetic crude oil, 15,600 bbls/day of diluent and 6,200 bbls/day of ultra low sulphur diesel in 2018. In addition, as by-products of its upgrading operations, the Upgrader produced approximately 355 long ton/day of sulphur and 1,005 long ton/day of petroleum coke during 2018. These products are sold in Canadian and international markets.

Canadian Refined Products

The Company's Canadian Refined Products operations include refining of light crude oil, manufacturing of fuel and fuel grade ethanol, manufacturing of asphalt products from heavy crude oil and bitumen and acquisition by purchase and exchange of refined petroleum products. The Company's retail distribution network includes the wholesale, commercial and retail marketing of refined petroleum products and provides a platform for non-fuel related convenience product businesses.

Light oil refined products are produced at the Prince George Refinery and are also acquired from third-party refiners and marketed through the Company's retail and commercial petroleum outlets and through direct marketing to third-party dealers and end users. Asphalt and residual products are produced at the Company's Asphalt Refinery at Lloydminster, Alberta and are marketed directly or through the Company's eight terminals located in western Canada and the U.S. midwest.

Lloydminster Asphalt Refinery
Husky's Asphalt Refinery in Lloydminster, Alberta processes heavy crude oil and bitumen into asphalt products used in road construction and maintenance. The refinery has a throughput capacity of 29,000 bbls/day of heavy crude oil and bitumen. The refinery also produces straight run gasoline, bulk distillates and residuals. 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. Residuals 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 27,100 bbls/day of blended heavy crude oil and bitumen feedstock during 2018. 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 Lloydminster Asphalt Refinery to run at or near full capacity throughout the year.

Asphalt Distribution Network
In addition to sales directly from the Lloydminster Asphalt Refinery, the Company, through the Husky 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 terminals asphalt from independently operated terminals in the states of Washington, Minnesota, Wisconsin and Ohio.

In 2019, the Company plans to increase asphalt modification capacity, expand sales in U.S. markets and further market residual products as refinery feedstock.

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 and both plants are currently operating above that capacity due to efforts to optimize yield. In 2018, ethanol production averaged 819.4 thousand 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.

Prince George Refinery

The Prince George Refinery provides refined products to the Company and third-party retail outlets in the central and northern regions of British Columbia. Feedstock is delivered to the refinery by pipeline from northeastern British Columbia. The refinery has a throughput capacity of 12,000 bbls/day.

The Prince George Refinery produces all grades of unleaded gasoline, seasonal diesel fuels, mixed propane and butane and heavy fuel oil. During 2018, throughput averaged 10,700 bbls/day.

On January 8, 2019, the Company announced its intention to market and potentially sell the Prince George Refinery.

Other Supply Arrangements

During 2018, the Company purchased approximately 28,200 bbls/day of refined petroleum products of which 27,200 bbls/day were from the agreement with Imperial Oil. The Company also acquired approximately 7,600 bbls/day of refined petroleum products pursuant to exchange agreements with third-party refiners in addition to Imperial Oil.

Retail and Commercial Network

During 2015, the Company and Imperial Oil entered into a contractual agreement to create a single expanded truck transport cardlock network of approximately 160 sites. The agreement has been fully implemented, and the consolidation of the two cardlock networks, under the Esso brand, was completed in the third quarter of 2017.

As at December 31, 2018, there were 554 independently operated Husky and Esso-branded petroleum product outlets. These outlets include travel centres, convenience stores, cardlock and bulk distribution facilities located from coast to coast. The Company's network of travel centres features a proprietary cardlock system that enables commercial customers to purchase products using a card system that processes transactions, provides detailed billing, fuel and sales tax information and offers advanced fraud protection. A variety of full and self-serve retail locations serve urban and rural markets across the network, while the Company's bulk distributors offer direct sales to commercial and agricultural markets in the Prairie provinces.

The Company's retail and commercial operating model is balanced by corporate-owned/dealer-operated and branded dealer owned and operated sites. 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 offers 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.

On January 8, 2019, the Company announced its intention to market and potentially sell its Retail and Commercial Network.

The following table shows the number of Husky and Esso-branded petroleum outlets by province as of December 31, 2018:

	British Columbia	Alberta	Saskatchewan	Manitoba	Ontario	Quebec	New Brunswick	**2018 Total**	2017 Total
Husky-Branded Petroleum Outlets									
Retail Owned Outlets	40	46	8	13	58	—	—	165	163
Leased	32	30	3	7	25	—	—	97	99
Independent Retailers	48	61	11	3	13	—	—	136	140
Total	**120**	**137**	**22**	**23**	**96**	**—**	**—**	**398**	402
Esso-Branded Petroleum Outlets									
Retail Owned Outlets	14	15	4	3	12	—	—	48	48
Leased	2	2	—	3	1	—	—	8	8
Independent Retailers	32	23	4	6	27	7	1	100	100
Total	**48**	**40**	**8**	**12**	**40**	**7**	**1**	**156**	156
Cardlocks[1]	**49**	**45**	**9**	**11**	**40**	**7**	**1**	**162**	167
Convenience Stores[1]	**82**	**85**	**14**	**21**	**94**	**—**	**—**	**296**	296
Restaurants	**8**	**9**	**3**	**1**	**13**	**—**	**—**	**34**	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:

	Years ended December 31,		
Average Daily Sales Volume *(mbbls/day)*	**2018**	2017	2016
Gasoline	**21.7**	22.3	22.4
Diesel fuel	**26.5**	22.8	18.5
Liquefied Petroleum Gas	**0.2**	0.2	0.2
	48.4	45.3	41.1

U.S. Refining and Marketing

Lima Refinery

The Lima Refinery has a crude oil throughput capacity, depending on crude slate, of up to 175,000 bbls/day. The Lima Refinery currently processes both light sweet crude oil and a small percentage of 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 2018, total production throughput at the Lima Refinery averaged 171,000 bbls/day excluding days for turnaround. Production excluding days for turnaround consisted of gasoline averaging 84,000 bbls/day, total distillates averaging 66,000 bbls/day and total other products averaging 21,000 bbls/day.

In 2016, the Company completed the first stage of the crude oil flexibility project and the refinery is now able to process up to 10,000 bbls/day of heavy crude oil feedstock. The project is designed to allow for the processing of up to 40,000 bbls/day of heavy crude oil from western Canada when completed, providing the ability to swing between light and heavy crude oil feedstock.

The timing of completion for the crude oil flexibility project is late 2019. This schedule coordinates project work with normal maintenance to provide higher levels of sustained production.

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 product.

During 2018, the Company's share of total throughput averaged 73,200 bbls/day, with the Company's share of production of gasoline averaging 42,600 bbls/day, distillates averaging 21,400 bbls/day and other fuel and feedstock averaging 9,100 bbls/day.

Superior Refinery

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

The refinery is responsible for the oversight of 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 refinery experienced an incident while preparing for a major turnaround. Operations at the refinery remain suspended. An engineering contractor has been appointed to oversee design work and rebuild of the refinery. The rebuild will commence once design work is complete and permits are obtained. Operations are expected to resume in 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, 2018**	**Dec 31, 2018**	Sept 30, 2018	June 30, 2018	Mar 31, 2018
Company Total[2]					
Sales volume *(mboe/day)*	**299.2**	**304.3**	296.7	295.5	300.4
Gross Revenue *($/boe)*[3]	**$41.50**	**$25.47**	$50.44	$49.74	$40.87
Royalties *($/boe)*	**$3.30**	**$2.08**	$4.24	$3.98	$2.98
Production and Operating Costs *($/boe)*[3]	**$14.00**	**$13.75**	$14.68	$14.22	$13.33
Transportation Costs *($/boe)*[4]	**$0.22**	**$0.22**	$0.22	$0.23	$0.19
Operating netback *($/boe)*	**$23.98**	**$9.42**	$31.30	$31.31	$24.37
Light and Medium Crude Oil *($/bbl)*					
Canada - Western Canada					
Gross Revenue[3]	**$55.71**	**$28.75**	$69.09	$70.51	$55.20
Royalties	**$8.70**	**$4.97**	$12.75	$9.08	$7.86
Production and Operating Costs[3]	**$29.90**	**$27.22**	$30.56	$32.82	$29.16
Operating netback	**$17.11**	**($3.44)**	$25.78	$28.61	$18.18
Canada - Atlantic Canada					
Gross Revenue	**$95.97**	**$83.41**	$104.08	$101.67	$90.70
Royalties	**$7.90**	**$7.35**	$7.89	$10.92	$5.94
Production and Operating Costs	**$27.21**	**$47.76**	$25.22	$29.65	$17.51
Transportation Costs[4]	**$3.01**	**$5.11**	$2.77	$3.31	$2.02
Operating netback	**$57.85**	**$23.19**	$68.20	$57.79	$65.23
Canada - Total					
Gross Revenue[3]	**$83.71**	**$60.19**	$93.84	$92.23	$82.08
Royalties	**$8.15**	**$6.34**	$9.31	$10.36	$6.41
Production and Operating Costs[3]	**$28.03**	**$39.03**	$26.79	$30.61	$20.34
Transportation Costs[4]	**$2.09**	**$2.94**	$1.96	$2.31	$1.53
Operating netback	**$45.44**	**$11.88**	$55.78	$48.95	$53.80
Heavy Crude Oil *($/bbl)*					
Canada - Total					
Gross Revenue[3]	**$39.26**	**$18.71**	$50.09	$54.22	$32.80
Royalties	**$3.89**	**$1.32**	$5.70	$5.49	$2.89
Production and Operating Costs[3]	**$27.96**	**$30.00**	$30.77	$25.61	$25.96
Operating netback	**$7.41**	**($12.61)**	$13.62	$23.12	$3.95
Bitumen *($/bbl)*					
Canada - Total					
Gross Revenue[3][4]	**$30.17**	**$5.42**	$46.00	$44.41	$27.77
Royalties	**$2.09**	**$0.56**	$3.33	$2.73	$1.95
Production and Operating Costs[3]	**$11.43**	**$11.09**	$12.04	$11.10	$11.54
Operating netback	**$16.65**	**($6.23)**	$30.63	$30.58	$14.28

Average Per Unit Amounts	Year Ended	Three Months Ended			
	Dec 31, 2018	Dec 31, 2018	Sept 30, 2018	June 30, 2018	Mar 31, 2018
Conventional Natural Gas *($/mcf)*					
Canada - Total					
Gross Revenue(3)(5)	**$1.79**	**$1.94**	$1.38	$1.49	$2.38
Royalties(5)(6)	**($0.12)**	**($0.05)**	($0.09)	($0.17)	($0.16)
Production and Operating Costs(3)	**$1.70**	**$1.37**	$1.83	$1.92	$1.69
Operating netback	**$0.21**	**$0.62**	($0.36)	($0.26)	$0.85
China					
Gross Revenue	**$13.73**	**$13.85**	$13.14	$13.96	$13.95
Royalties	**$0.80**	**$0.86**	$0.76	$0.82	$0.74
Production and Operating Costs	**$0.77**	**$0.66**	$0.81	$0.89	$0.71
Operating netback	**$12.16**	**$12.33**	$11.57	$12.25	$12.50
Indonesia(7)					
Gross Revenue	**$9.81**	**$9.76**	$9.79	$9.82	$9.85
Royalties	**$1.07**	**$1.09**	$1.07	$1.07	$1.02
Production and Operating Costs	**$1.67**	**$1.77**	$1.66	$1.37	$1.98
Operating netback	**$7.07**	**$6.90**	$7.06	$7.38	$6.85
Total					
Gross Revenue(3)	**$6.64**	**$6.86**	$6.15	$6.53	$7.03
Royalties	**$0.29**	**$0.36**	$0.30	$0.26	$0.23
Production and Operating Costs(3)	**$1.36**	**$1.14**	$1.46	$1.51	$1.33
Operating netback	**$4.99**	**$5.36**	$4.39	$4.76	$5.47
Natural Gas Liquids *($/bbl)*					
Canada - Total					
Gross Revenue(3)	**$35.71**	**$31.65**	$36.37	$36.54	$38.76
Royalties	**$9.58**	**$7.13**	$8.43	$10.83	$12.26
Production and Operating Costs(3)	**$9.97**	**$7.82**	$11.17	$11.28	$9.72
Operating netback	**$16.16**	**$16.70**	$16.77	$14.43	$16.78
China					
Gross Revenue	**$72.77**	**$69.76**	$76.13	$71.88	$73.60
Royalties	**$4.21**	**$4.03**	$4.28	$4.42	$4.14
Production and Operating Costs	**$4.59**	**$3.95**	$4.86	$5.36	$4.28
Operating netback	**$63.97**	**$61.78**	$66.99	$62.10	$65.18
Indonesia(7)					
Gross Revenue	**$95.67**	**$96.83**	$95.61	$98.37	$87.53
Royalties	**$14.96**	**$15.15**	$15.03	$15.16	$13.72
Production and Operating Costs	**$10.04**	**$10.65**	$9.95	$8.20	$11.86
Operating netback	**$70.67**	**$71.03**	$70.63	$75.01	$61.95
Total					
Gross Revenue(3)	**$55.72**	**$53.36**	$60.08	$54.13	$55.03
Royalties	**$8.19**	**$6.88**	$8.13	$8.90	$9.08
Production and Operating Costs(3)	**$8.00**	**$6.69**	$8.80	$8.93	$7.65
Operating netback	**$39.53**	**$39.79**	$43.15	$36.30	$38.30

(1) The operating netback includes results from Upstream Exploration and Production and excludes results from Upstream Infrastructure and Marketing. 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 financial statement purposes.

Production History

Average Gross Daily Production[1]	Year Ended Dec 31, 2018	Three Months Ended Dec 31, 2018	Sept 30, 2018	June 30, 2018	Mar 31, 2018
Canada - Western Canada					
Light and Medium Crude Oil *(mbbls/day)*	**9.4**	**9.6**	9.9	9.0	9.1
Heavy Crude Oil *(mbbls/day)*	**36.8**	**34.4**	34.6	38.5	39.7
Bitumen *(mbbls/day)*	**124.2**	**132.9**	117.3	123.2	123.2
Conventional Natural Gas *(mmcf/day)*	**291.0**	**302.6**	297.6	285.0	278.7
NGL *(mbbls/day)*	**12.0**	**12.7**	11.9	12.3	11.3
Canada - Atlantic					
Light and Medium Crude Oil *(mbbls/day)*	**21.4**	**13.0**	23.8	20.7	28.4
China - Asia Pacific[2]					
Conventional Natural Gas *(mmcf/day)*	**184.8**	**197.0**	181.9	180.3	179.7
NGL *(mbbls/day)*	**8.4**	**9.3**	8.4	7.7	8.2
Indonesia - Asia Pacific[3]					
Conventional Natural Gas *(mmcf/day)*	**31.2**	**38.0**	40.0	28.7	18.6
NGL *(mbbls/day)*	**2.5**	**2.8**	4.2	1.8	1.0
Total Gross Production *(mboe/day)*	**299.2**	**304.3**	296.7	295.5	300.4

(1) Total production volumes for 2018, for each product type, are set forth in the Reconciliation of Gross Proved Plus Probable Reserves table.
(2) Reported production volumes include Husky's working interest production from the Liwan Gas Project (49 percent).
(3) Reported production volumes include Husky's working interest production from the BD Project (40 percent). 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	Natural Gas Wells Gross	Natural Gas Wells Net	Total Gross	Total Net
Canada						
Alberta	1,712	1,507	1,975	1,406	3,687	2,913
Saskatchewan	2,678	2,596	88	86	2,766	2,682
British Columbia	—	—	121	121	121	121
Newfoundland	22	6	—	—	22	6
	4,412	4,109	2,184	1,613	6,596	5,722
International						
China	—	—	10	5	10	5
Indonesia	—	—	4	2	4	2
	—	—	14	7	14	7
As at December 31, 2018	**4,412**	**4,109**	**2,198**	**1,620**	**6,610**	**5,729**

Non-Producing Wells	Oil Wells Gross	Oil Wells Net	Natural Gas Wells Gross	Natural Gas Wells Net	Total Gross	Total Net
Canada						
Alberta	1,733	1,598	1,159	931	2,892	2,529
Saskatchewan	4,100	3,937	213	192	4,313	4,129
British Columbia	—	—	11	9	11	9
As at December 31, 2018	**5,833**	**5,535**	**1,383**	**1,132**	**7,216**	**6,667**

(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, 2018.
(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, 2018, the Company had a royalty interest in 885 wells, of which 481 were oil producers and 404 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 2018, there were 1,054 gross and 952 net oil wells and 92 gross and 78 net natural gas wells that were completed in two or more formations and from which production is not commingled.

Of the 16 mmboe of Proved Developed Non-Producing reserves as of year-end 2018, approximately 10 mmboe are associated with wells drilled in 2018 that will be placed on production in 2019 and 2020. The remaining volumes are associated with 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	3,340	2,819
Saskatchewan	628	609
British Columbia	201	160
	4,169	3,588
Northwest Territories and Arctic	552	521
Atlantic	2,058	1,094
	6,779	5,203
China	787	776
Indonesia	2,033	1,664
Taiwan	1,904	1,428
As at December 31, 2018	**11,504**	**9,071**

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, 2018, over the next 12 months, development rights to approximately 247 thousand net acres, or less than seven percent, of the Company's net unproved acreage in Western Canada will be subject to expiry.

As at December 31, 2018, over the next 12 months, development rights to the 1,428 thousand net acres in Taiwan are subject to expiry. The Company is analyzing the 3-D survey from 2017 to identify potential drilling prospects and is evaluating options to extend the expiry to beyond 2019 or proceed to the exploration phase.

The Company has commitments totaling approximately $69 million related to exploration to be completed in Atlantic between 2022 and 2023. Not fulfilling commitments on a timely basis commonly triggers forfeiture of security deposits of 25 percent of unfulfilled commitments.

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 16 of the Company's audited consolidated financial statements for the year ended December 31, 2018.

Drilling Activity - Number of Wells Drilled

	Year Ended December 31, 2018							
	Western Canada		Atlantic		China		Indonesia	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Exploration								
Oil	2.0	2.0	1.0	0.7	3.0	3.0	—	—
Gas	4.0	4.0	—	—	—	—	—	—
	6.0	6.0	1.0	0.7	3.0	3.0	—	—
Development								
Oil	194.0	180.0	1.0	0.7	—	—	—	—
Gas	27.0	25.0	—	—	—	—	—	—
	221.0	205.0	1.0	0.7	—	—	—	—
	227.0	**211.0**	**2.0**	**1.4**	**3.0**	**3.0**	**—**	**—**
Stratigraphic Test Wells	**15.0**	**13.0**	**—**	**—**	**—**	**—**	**—**	**—**
Service Wells	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**

Costs Incurred

($millions)	Total	Western Canada	Atlantic	Total Canada	China	Indonesia[(1)]
Property acquisition - Unproven	11	11	—	11	—	—
Property acquisition - Proven	34	34	—	34	—	—
Exploration	245	110	72	182	63	—
Development	2,446	1,310	963	2,273	150	23
2018	**2,736**	**1,465**	**1,035**	**2,500**	**213**	**23**

(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 Ltd. ("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. Sproule has also this year executed the Form 51-101F2 attached as Appendix B to this AIF.

The Audit Committee of the Board of Directors 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 of Directors 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 31, 2019 and an effective date of December 31, 2018 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 are reserves or production net of such royalties. 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 as issued by the International Accounting Standards Board. 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 thermal projects in Husky's Lloydminster area. These projects also contain heavy oil that is lighter and less viscous than typical bitumen.

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 or on the Company's website at www.huskyenergy.com. The material differences 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 Natural Gas Reserves
As at December 31, 2018
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	41.1	35.5	52.0	49.7	135.0	123.0	228.2	208.2
Developed Non-producing	0.6	0.5	0.7	0.6	6.8	6.3	8.0	7.4
Undeveloped	69.8	64.2	1.0	0.9	747.9	651.5	818.6	716.6
Total Proved	111.5	100.3	53.7	51.2	889.7	780.7	1,054.9	932.2
Probable	89.2	73.1	21.9	20.5	831.8	632.1	942.9	725.7
Total Proved Plus Probable	**200.6**	**173.3**	**75.6**	**71.7**	**1,721.5**	**1,412.8**	**1,997.8**	**1,657.8**

	Conventional Natural Gas *(bcf)*		Natural Gas Liquids *(mmbbls)*		Total *(mmboe)*	
	Gross	Net	Gross	Net	Gross	Net
Proved						
Developed Producing	771.0	674.0	37.0	27.1	393.7	347.6
Developed Non-producing	32.7	30.1	2.5	2.1	16.0	14.5
Undeveloped	484.5	454.5	6.9	6.0	906.3	798.4
Total Proved	1,288.1	1,158.6	46.3	35.2	1,315.9	1,160.5
Probable	462.9	425.9	10.7	8.4	1,030.7	805.1
Total Proved Plus Probable	**1,751.0**	**1,584.5**	**57.0**	**43.7**	**2,346.7**	**1,965.6**

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	376.1	356.2	12.8	12.1	75.5	71.5
Developed Non-producing	—	—	—	—	—	—
Undeveloped	153.6	150.3	5.5	5.4	31.1	30.5
Total Proved	529.6	506.5	18.3	17.5	106.6	101.9
Probable	109.0	103.2	4.1	3.9	22.2	21.1
Total Proved Plus Probable	**638.7**	**609.7**	**22.4**	**21.4**	**128.8**	**123.0**

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	152.7	112.6	6.1	4.7	31.5	23.4
Developed Non-producing	—	—	—	—	—	—
Undeveloped	101.0	69.1	—	—	16.8	11.5
Total Proved	253.7	181.8	6.1	4.7	48.3	34.9
Probable	91.5	50.1	1.7	0.5	16.9	8.9
Total Proved Plus Probable	**345.1**	**231.8**	**7.7**	**5.2**	**65.3**	**43.8**

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	41.1	35.5	52.0	49.7	135.0	123.0	228.2	208.2
Developed Non-producing	0.6	0.5	0.7	0.6	6.8	6.3	8.0	7.4
Undeveloped	69.8	64.2	1.0	0.9	747.9	651.5	818.6	716.6
Total Proved	111.5	100.3	53.7	51.2	889.7	780.7	1,054.9	932.2
Probable	89.2	73.1	21.9	20.5	831.8	632.1	942.9	725.7
Total Proved Plus Probable	**200.6**	**173.3**	**75.6**	**71.7**	**1,721.5**	**1,412.8**	**1,997.8**	**1,657.8**

	Conventional Natural Gas *(bcf)*		Natural Gas Liquids *(mmbbls)*		Total *(mmboe)*	
	Gross	Net	Gross	Net	Gross	Net
Proved						
Developed Producing	1,299.7	1,142.8	55.8	43.9	500.7	442.5
Developed Non-producing	32.7	30.1	2.5	2.1	16.0	14.5
Undeveloped	739.1	674.0	12.4	11.4	954.2	840.4
Total Proved	2,071.4	1,846.8	70.7	57.4	1,470.8	1,297.4
Probable	663.4	579.2	16.4	12.8	1,069.9	835.0
Total Proved Plus Probable	**2,734.8**	**2,426.0**	**87.1**	**70.2**	**2,540.7**	**2,132.4**

Future Net Revenue Tables

Summary of Net Present Values of Future Net Revenue - Before Income Taxes and Discounted
As at December 31, 2018
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	321.4	3,483.6	3,694.7	3,510.8	3,273.1	10.63
Developed Non-producing[(1)]	(1,068.6)	(559.3)	(334.4)	(219.2)	(153.6)	(23.08)
Undeveloped	19,758.6	9,137.0	5,067.3	2,930.0	1,628.8	6.35
Total Proved	19,011.3	12,061.3	8,427.6	6,221.6	4,748.3	7.26
Probable	35,304.5	15,561.8	9,098.9	6,081.8	4,375.9	11.30
Total Proved Plus Probable	**54,315.8**	**27,623.1**	**17,526.5**	**12,303.5**	**9,124.2**	**8.92**

(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	4,702.3	3,980.9	3,448.3	3,043.4	2,727.6	48.24
Developed Non-producing	—	—	—	—	—	—
Undeveloped	1,282.4	797.1	479.2	263.5	112.7	15.73
Total Proved	5,984.7	4,778.0	3,927.5	3,306.9	2,840.3	38.53
Probable	1,260.8	767.5	510.7	367.0	280.6	24.24
Total Proved Plus Probable	**7,245.5**	**5,545.5**	**4,438.2**	**3,673.9**	**3,120.9**	**36.08**

Indonesia

	Before Income Taxes and Discounted at (%/year)					Unit Value Discounted at 10%
($ millions)	0%	5%	10%	15%	20%	*($/boe)*
Proved						
Developed Producing	602.0	501.5	428.8	374.6	333.0	18.30
Developed Non-producing	—	—	—	—	—	—
Undeveloped	348.4	284.1	234.5	195.4	164.0	20.35
Total Proved	950.4	785.6	663.3	570.0	497.1	18.98
Probable	416.5	270.5	183.2	128.6	93.1	20.68
Total Proved Plus Probable	**1,366.9**	**1,056.1**	**846.5**	**698.6**	**590.2**	**19.32**

Total

($ millions)	Before Income Taxes and Discounted at (%/year) 0%	5%	10%	15%	20%	Unit Value Discounted at 10% ($/boe)
Proved						
Developed Producing	5,625.7	7,965.9	7,571.9	6,928.9	6,333.7	17.11
Developed Non-producing[(1)]	(1,068.6)	(559.3)	(334.4)	(219.2)	(153.6)	(23.08)
Undeveloped	21,389.3	10,218.3	5,781.0	3,388.9	1,905.6	6.88
Total Proved	25,946.5	17,624.9	13,018.4	10,098.5	8,085.6	10.03
Probable	36,981.8	16,599.8	9,792.8	6,577.4	4,749.7	11.73
Total Proved Plus Probable	**62,928.2**	**34,224.7**	**22,811.2**	**16,676.0**	**12,835.3**	**10.70**

(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, 2018
Forecast Prices and Costs

Canada

	After Income Taxes and Discounted at (%/year)				
($ millions)	0%	5%	10%	15%	20%
Proved					
Developed Producing	215.4	2,496.4	2,640.6	2,503.7	2,330.6
Developed Non-producing[(1)]	(780.1)	(409.0)	(245.3)	(161.5)	(113.9)
Undeveloped	14,093.8	6,297.9	3,275.4	1,683.0	717.0
Total Proved	13,529.2	8,385.4	5,670.7	4,025.1	2,933.7
Probable	25,415.5	11,090.9	6,423.2	4,254.2	3,034.0
Total Proved Plus Probable	**38,944.6**	**19,476.2**	**12,093.9**	**8,279.3**	**5,967.7**

(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	3,523.8	2,984.1	2,585.9	2,283.5	2,047.7
Developed Non-producing	—	—	—	—	—
Undeveloped	955.6	566.7	310.7	136.4	14.3
Total Proved	4,479.4	3,550.8	2,896.6	2,419.9	2,062.0
Probable	945.2	575.4	382.9	275.2	210.6
Total Proved Plus Probable	**5,424.5**	**4,126.1**	**3,279.5**	**2,695.1**	**2,272.5**

Indonesia

	After Income Taxes and Discounted at (%/year)				
($ millions)	0%	5%	10%	15%	20%
Proved					
Developed Producing	465.8	399.7	350.3	312.3	282.3
Developed Non-producing	—	—	—	—	—
Undeveloped	252.3	206.6	170.9	142.5	119.5
Total Proved	718.1	606.3	521.2	454.8	401.9
Probable	251.6	162.5	109.2	75.8	54.1
Total Proved Plus Probable	**969.7**	**768.8**	**630.4**	**530.7**	**456.0**

Total

	After Income Taxes and Discounted at (%/year)				
($ millions)	0%	5%	10%	15%	20%
Proved					
Developed Producing	4,204.9	5,880.1	5,576.9	5,099.5	4,660.6
Developed Non-producing[(1)]	(780.1)	(409.0)	(245.3)	(161.5)	(113.9)
Undeveloped	15,301.8	7,071.2	3,757.0	1,961.9	850.8
Total Proved	18,726.7	12,542.4	9,088.5	6,899.9	5,397.6
Probable	26,612.2	11,828.7	6,915.3	4,605.2	3,298.6
Total Proved Plus Probable	**45,338.9**	**24,371.1**	**16,003.8**	**11,505.1**	**8,696.2**

(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, 2018
Forecast Prices and Costs

($ millions)	Revenue	Royalties	Operating Costs	Develop-ment Costs	Abandon-ment and Reclama-tion Costs	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
Canada								
Total Proved	79,702.3	10,674.3	30,796.6	12,441.0	6,779.0	19,011.3	5,482.2	13,529.2
Total Proved Plus Probable	156,537.5	28,954.4	45,725.0	20,550.2	6,992.0	54,315.8	15,371.2	38,944.6
China								
Total Proved	8,203.1	454.8	1,022.9	553.9	186.8	5,984.7	1,505.3	4,479.4
Total Proved Plus Probable	9,937.5	549.7	1,401.3	553.9	187.2	7,245.5	1,821.0	5,424.5
Indonesia								
Total Proved	2,896.2	779.8	1,070.8	55.9	39.3	950.4	232.3	718.1
Total Proved Plus Probable	4,107.5	1,349.4	1,250.7	96.4	44.0	1,366.9	397.2	969.7
Total								
Total Proved	90,801.6	11,909.0	32,890.3	13,050.8	7,005.1	25,946.5	7,219.8	18,726.7
Total Proved Plus Probable	170,582.5	30,853.6	48,377.0	21,200.5	7,223.2	62,928.2	17,589.4	45,338.9

Future Net Revenue by Product Type
As at December 31, 2018
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	342.6	2.09	—	—	—	—	342.6	2.09
Heavy Crude Oil	(221.4)	(4.21)	—	—	—	—	(221.4)	(4.21)
Bitumen	7,720.8	9.89	—	—	—	—	7,720.8	9.89
Total Oil	7,842.0	7.86	—	—	—	—	7,842.0	7.86
Conventional Natural Gas	585.6	3.59	3,927.5	38.53	663.3	18.98	5,176.4	17.24
Total Proved	**8,427.6**	**7.26**	**3,927.5**	**38.53**	**663.3**	**18.98**	**13,018.4**	**10.03**
Total Proved Plus Probable								
Light & Medium Crude Oil	2,615.0	10.80	—	—	—	—	2,615.0	10.80
Heavy Crude Oil	125.5	1.70	—	—	—	—	125.5	1.70
Bitumen	13,743.0	9.73	—	—	—	—	13,743.0	9.73
Total Oil	16,483.5	9.54	—	—	—	—	16,483.5	9.54
Conventional Natural Gas	1,043.0	4.40	4,438.2	36.08	846.5	19.32	6,327.7	15.68
Total Proved Plus Probable	**17,526.5**	**8.92**	**4,438.2**	**36.08**	**846.5**	**19.32**	**22,811.2**	**10.70**

(1) By-products, including solution gas, NGL and other associated by-products, are included in their main product group (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 Associates Limited and GLJ Petroleum Consultants Ltd. China and Indonesia gas prices are derived from the GSAs specific to each set of projects. For historical prices realized during 2018, 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					
2018	64.77	70.97	69.31	52.33	39.33
Forecast					
2019	58.58	65.92	67.30	52.61	43.92
2020	64.60	69.47	75.84	60.50	52.76
2021	68.20	71.65	80.17	66.60	59.10
2022	71.00	73.72	83.22	69.32	61.60
2023	72.81	75.58	85.34	71.25	63.39
2024	74.59	77.39	87.33	73.07	65.14
2025	76.42	79.27	89.50	75.08	66.99
2026	78.40	81.27	91.89	77.22	69.06
2027	79.98	82.88	93.76	78.89	70.60
2028	81.59	84.54	95.68	80.60	72.17
Thereafter	2.00%/yr	2.00%/yr	2.00%/yr	2.00%/yr	2.00%/yr

	Bitumen	Natural Gas	Natural Gas Liquids		
	Hardisty WCS *(Cdn $/bbl)*	AECO *(Cdn $/mmbtu)*	Edmonton Propane *(Cdn $/bbl)*	Edmonton Butane *(Cdn $/bbl)*	Edmonton Condensate *(Cdn $/bbl)*
Historical					
2018	49.82	1.53	27.25	33.29	78.95
Forecast					
2019	51.55	1.88	26.13	27.32	70.10
2020	59.58	2.31	31.27	41.10	79.21
2021	65.89	2.74	34.58	49.28	83.33
2022	68.61	3.05	37.25	55.65	86.20
2023	70.53	3.21	38.73	57.92	88.16
2024	72.34	3.31	39.75	59.27	90.20
2025	74.31	3.39	40.76	60.77	92.43
2026	76.44	3.46	41.93	62.37	94.87
2027	78.10	3.54	42.84	63.65	96.80
2028	79.81	3.62	43.80	64.97	98.79
Thereafter	2.00%/yr	2.00%/yr	2.00%/yr	2.00%/yr	2.00%/yr

	Asia Pacific			
	China	Indonesia		
	Natural Gas *(U.S. $/mcf)*[(1)]	Natural Gas *(U.S. $/mcf)*[(1)]	Inflation rates[(2)]	Exchange rates[(3)]
Historical				
2018	10.60	7.56	—	0.77
Forecast				
2019	10.55	7.53	—	0.76
2020	11.33	6.98	2.00	0.78
2021	10.94	7.10	2.00	0.80
2022	9.87	7.25	2.00	0.80
2023	9.89	7.37	2.00	0.81
2024	9.89	7.54	2.00	0.81
2025	9.89	7.70	2.00	0.81
2026	9.89	7.83	2.00	0.81
2027	9.90	7.98	2.00	0.81
2028	9.93	8.10	2.00	0.81
Thereafter			2.00	0.84

(1) 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 2017	24.6	63.8	747.4	835.8	1,174.1	41.4	1,073.0
Technical Revisions	(4.5)	2.1	8.3	5.9	4.0	2.3	8.9
Economic Factors	—	(3.4)	0.1	(3.2)	(9.7)	(0.1)	(5.0)
Acquisitions	—	—	2.2	2.2	8.4	0.3	3.9
Dispositions	(0.4)	(0.2)	—	(0.5)	(1.9)	—	(0.9)
Discoveries	0.1	—	—	0.1	0.1	—	0.1
Extensions & Improved Recovery	1.7	4.7	177.1	183.5	219.4	6.8	226.9
Production	(3.4)	(13.4)	(45.3)	(62.2)	(106.2)	(4.4)	(84.3)
End of 2018	**18.2**	**53.7**	**889.7**	**961.6**	**1,288.1**	**46.3**	**1,222.6**
Canada - Atlantic							
End of 2017	96.8	—	—	96.8	—	—	96.8
Technical Revisions	(3.3)	—	—	(3.3)	—	—	(3.3)
Economic Factors	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—
Extensions & Improved Recovery	7.6	—	—	7.6	—	—	7.6
Production	(7.8)	—	—	(7.8)	—	—	(7.8)
End of 2018	**93.3**	**—**	**—**	**93.3**	**—**	**—**	**93.3**
China							
End of 2017	—	—	—	—	397.9	14.0	80.3
Technical Revisions	—	—	—	—	45.6	1.9	9.5
Economic Factors	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—
Discoveries	—	—	—	—	153.6	5.5	31.1
Extensions & Improved Recovery	—	—	—	—	—	—	—
Production	—	—	—	—	(67.4)	(3.1)	(14.3)
End of 2018	**—**	**—**	**—**	**—**	**529.6**	**18.3**	**106.6**
Indonesia							
End of 2017	—	—	—	—	264.0	6.9	50.9
Technical Revisions	—	—	—	—	1.1	—	0.2
Economic Factors	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	—	—	—	—
Production	—	—	—	—	(11.5)	(0.9)	(2.8)
End of 2018	**—**	**—**	**—**	**—**	**253.7**	**6.1**	**48.3**

	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 2017	121.5	63.8	747.4	932.7	1,836.1	62.4	1,301.1
Technical Revisions	(7.7)	2.1	8.3	2.6	50.7	4.2	15.3
Economic Factors	—	(3.4)	0.1	(3.2)	(9.7)	(0.1)	(5.0)
Acquisitions	—	—	2.2	2.2	8.4	0.3	3.9
Dispositions	(0.4)	(0.2)	—	(0.5)	(1.9)	—	(0.9)
Discoveries	0.1	—	—	0.1	153.6	5.5	31.2
Extensions & Improved Recovery	9.3	4.7	177.1	191.1	219.4	6.8	234.5
Production	(11.3)	(13.4)	(45.3)	(70.0)	(185.1)	(8.4)	(109.2)
End of 2018	**111.5**	**53.7**	**889.7**	**1,054.9**	**2,071.4**	**70.7**	**1,470.8**

At December 31, 2018, the Company's proved oil and gas reserves were 1,471 mmboe, up from 1,301 mmboe at the end of 2017. The Company's 2018 reserves replacement ratio, defined as net additions of proved reserves divided by total production during the period, was 260 percent excluding economic revisions (255 percent including economic revisions).

Major changes to proved reserves in 2018 included:

- Western Canada Extensions & Improved Recovery additions of 227 mmboe including 102 mmbbls in the Sunrise Energy Project from new locations as part of a full field optimized development plan, 63 mmbbls for two new Lloydminster thermal bitumen SAGD projects, and 43 mmboe in Ansell, Kakwa, North Blackstone, Wapiti and Wembley from new locations.
- Discoveries included 154 bcf of conventional natural gas and 5 mmbbls of NGL for Liuhua 29-1 with the volumes transferred from probable reserves as Technical Revisions.
- Strong Lloydminster thermal bitumen performance added 31 mmbbls which were offset by a reduction of 23 mmbbls at the Sunrise Energy Project as a result of applying a more conservative estimate of the recovery factor early in the fifty-year life of the field.
- Atlantic Extensions & Improved Recovery include the addition of 8 mmbbls for the West White Rose Project transferred from probable as Technical Revisions.
- Technical Revisions of 9 mmboe in China due to higher natural gas performance as a transfer from probable reserves.
- Economic Factors include 4 mmboe associated with the shut-in of producing wells required because of the production curtailment implemented by the Government of Alberta.

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 2017	6.5	21.8	861.8	890.0	422.5	7.5	967.9
Technical Revisions	(2.1)	(2.6)	(295.1)	(299.8)	(37.3)	(0.1)	(306.1)
Economic Factors	0.1	—	1.0	1.1	(4.0)	(0.1)	0.3
Acquisitions	—	—	0.5	0.5	2.1	0.1	1.0
Dispositions	(0.1)	—	—	(0.1)	(0.1)	—	(0.1)
Discoveries	0.1	—	—	0.1	—	—	0.1
Extensions & Improved Recovery	0.9	2.8	263.6	267.3	79.6	3.3	283.9
Production	—	—	—	—	—	—	—
End of 2018	**5.4**	**21.9**	**831.8**	**859.1**	**462.9**	**10.7**	**946.9**
Canada - Atlantic							
End of 2017	99.4	—	—	99.4	—	—	99.4
Technical Revisions	(15.7)	—	—	(15.7)	—	—	(15.7)
Economic Factors	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	—	—	—	—
Production	—	—	—	—	—	—	—
End of 2018	**83.8**	**—**	**—**	**83.8**	**—**	**—**	**83.8**
China							
End of 2017	—	—	—	—	214.0	7.6	43.2
Technical Revisions	—	—	—	—	(185.2)	(6.4)	(37.3)
Economic Factors	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	80.3	2.9	16.3
Dispositions	—	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	—	—	—	—
Production	—	—	—	—	—	—	—
End of 2018	**—**	**—**	**—**	**—**	**109.0**	**4.1**	**22.2**
Indonesia							
End of 2017	—	—	—	—	138.5	2.0	25.1
Technical Revisions	—	—	—	—	(47.0)	(0.4)	(8.2)
Economic Factors	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	—	—	—	—
Production	—	—	—	—	—	—	—
End of 2018	**—**	**—**	**—**	**—**	**91.5**	**1.7**	**16.9**

	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 2017	105.9	21.8	861.8	989.5	775.0	17.1	1,135.7
Technical Revisions	(17.7)	(2.6)	(295.1)	(315.4)	(269.5)	(6.9)	(367.3)
Economic Factors	0.1	—	1.0	1.1	(4.0)	(0.1)	0.3
Acquisitions	—	—	0.5	0.5	82.4	3.0	17.3
Dispositions	(0.1)	—	—	(0.1)	(0.1)	—	(0.1)
Discoveries	0.1	—	—	0.1	—	—	0.1
Extensions & Improved Recovery	0.9	2.8	263.6	267.3	79.6	3.3	283.9
Production	—	—	—	—	—	—	—
End of 2018	**89.2**	**21.9**	**831.8**	**942.9**	**663.4**	**16.4**	**1,069.9**

Major changes to probable reserves in 2018 included:

- Western Canada Extensions & Improved Recovery additions of 284 mmboe including 246 mmbbls from new Sunrise Energy Project locations which were offset by negative Technical Revisions of 263 mmbbls for other locations no longer part of the optimized development plan.
- Other Extensions and Improved Recovery include 17 mmbbls for two new Lloydminster thermal bitumen SAGD projects, and 16 mmboe for new locations in Ansell, Kakwa, Wembley and other fields. Other Technical Revisions include the transfer of 18 mmbbls to Proved reserves for the Lloydminster thermal bitumen SAGD projects due to strong performance.
- The working interest in Liuhua 29-1 increased from 50 percent to 75 percent resulting in an acquisition of 16 mmboe.
- Indonesia negative Technical Revisions of 8 mmboe were a result of a GSA not being finalized for one of the fields.

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 2017	31.1	85.6	1,609.2	1,725.8	1,596.7	48.9	2,040.9
Technical Revisions	(6.5)	(0.5)	(286.8)	(293.8)	(33.3)	2.2	(297.2)
Economic Factors	0.2	(3.4)	1.1	(2.2)	(13.8)	(0.2)	(4.7)
Acquisitions	—	—	2.7	2.7	10.5	0.4	4.9
Dispositions	(0.4)	(0.2)	—	(0.7)	(1.9)	—	(1.0)
Discoveries	0.1	—	—	0.1	0.1	—	0.2
Extensions & Improved Recovery	2.6	7.5	440.7	450.8	298.9	10.1	510.8
Production	(3.4)	(13.4)	(45.3)	(62.2)	(106.2)	(4.4)	(84.3)
End of 2018	**23.5**	**75.6**	**1,721.5**	**1,820.7**	**1,751.0**	**57.0**	**2,169.6**
Canada - Atlantic							
End of 2017	196.3	—	—	196.3	—	—	196.3
Technical Revisions	(18.9)	—	—	(18.9)	—	—	(18.9)
Economic Factors	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—
Extensions & Improved Recovery	7.6	—	—	7.6	—	—	7.6
Production	(7.8)	—	—	(7.8)	—	—	(7.8)
End of 2018	**177.1**	**—**	**—**	**177.1**	**—**	**—**	**177.1**
China							
End of 2017	—	—	—	—	611.9	21.6	123.6
Technical Revisions	—	—	—	—	(139.6)	(4.6)	(27.8)
Economic Factors	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	80.3	2.9	16.3
Dispositions	—	—	—	—	—	—	—
Discoveries	—	—	—	—	153.6	5.5	31.1
Extensions & Improved Recovery	—	—	—	—	—	—	—
Production	—	—	—	—	(67.4)	(3.1)	(14.3)
End of 2018	**—**	**—**	**—**	**—**	**638.7**	**22.4**	**128.8**
Indonesia							
End of 2017	—	—	—	—	402.5	9.0	76.1
Technical Revisions	—	—	—	—	(45.9)	(0.4)	(8.0)
Economic Factors	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	—	—	—	—
Production	—	—	—	—	(11.5)	(0.9)	(2.8)
End of 2018	**—**	**—**	**—**	**—**	**345.1**	**7.7**	**65.3**

	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 2017	227.4	85.6	1,609.2	1,922.1	2,611.1	79.5	2,436.8
Technical Revisions	(25.5)	(0.5)	(286.8)	(312.8)	(218.8)	(2.8)	(352.0)
Economic Factors	0.2	(3.4)	1.1	(2.2)	(13.8)	(0.2)	(4.7)
Acquisitions	—	—	2.7	2.7	90.8	3.4	21.2
Dispositions	(0.4)	(0.2)	—	(0.7)	(1.9)	—	(1.0)
Discoveries	0.1	—	—	0.1	153.7	5.5	31.2
Extensions & Improved Recovery	10.2	7.5	440.7	458.4	298.9	10.1	518.3
Production	(11.3)	(13.4)	(45.3)	(70.0)	(185.1)	(8.4)	(109.2)
End of 2018	**200.6**	**75.6**	**1,721.5**	**1,997.8**	**2,734.8**	**87.1**	**2,540.7**

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 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 45 percent 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 34 percent of Husky's gross proved undeveloped reserves are assigned to 14 heavy oil thermal projects in the Lloydminster area that are classified as bitumen. Approximately eight percent of Husky's gross proved undeveloped reserves are assigned to the liquids-rich Ansell area. Approximately five percent of Husky's gross proved undeveloped reserves are assigned to the International area. Approximately seven percent of Husky's gross proved undeveloped reserves are assigned to the West White Rose Project fields and were added in 2017 and 2018 with the sanctioning of the project by Husky and its partners.

Husky funds 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 are pursued at a pace dependent on capital availability and its allocation in accordance with Husky's business plans. As at December 31, 2018, there were no material proved undeveloped reserves that have remained undeveloped for greater than five years, except as described below.

The Sunrise Energy Project proved undeveloped thermal 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. Similarly, the probable undeveloped bitumen reserves are scheduled to be developed and produced over the next 50 years which includes capital spending on facility debottlenecks, expansions and additions within the next five years. For the existing three Lloydminster thermal bitumen projects, one project is scheduled to start up in 2019, and two in 2020. Two new Lloydminster thermal bitumen projects received regulatory approval in early 2019 and are scheduled to be brought online in 2021 and 2022. The Lloydminster thermal bitumen proved and probable undeveloped locations and Tucker bitumen probable locations are scheduled to be developed over the next one to 20 years to utilize each of the project's steam and processing capacities. The West White Rose Project is scheduled to have the first proved undeveloped reserves placed on production in 2022. The remaining proved and probable undeveloped locations are scheduled to be placed on production by 2028. Proved undeveloped reserves in Madura are scheduled to be brought on production in 2020. Proved undeveloped reserves for Liuhua 29-1 are scheduled to be brought on production in 2020. Ansell's proved and probable undeveloped locations are scheduled to be developed over the next five and seven years, respectively, all in keeping with the the Company's business plan for that project.

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
2016	—	5.7	—	0.3	9.1	488.3	9.1	494.3
2017	61.8	60.8	—	—	136.9	585.0	198.7	645.9
2018	**8.4**	**69.8**	**1.0**	**1.0**	**177.3**	**747.9**	**186.6**	**818.6**

	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
2016	1.6	435.2	—	3.2	9.4	570.0
2017	71.9	451.6	1.0	3.6	211.6	724.7
2018	**310.4**	**739.1**	**9.2**	**12.4**	**247.6**	**954.2**

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
2016	11.8	133.7	—	0.1	1.3	1,234.0	13.1	1,367.7
2017	0.3	80.8	—	—	42.3	810.9	42.7	891.8
2018	**0.7**	**71.2**	**1.9**	**2.2**	**265.6**	**778.4**	**268.2**	**851.8**

	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
2016	48.1	345.4	0.4	3.4	21.5	1,428.7
2017	302.7	558.8	7.1	9.0	100.2	993.9
2018	**139.0**	**472.2**	**4.9**	**7.8**	**296.2**	**938.3**

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. For additional information on risk factors please see "Risk Factors – Reserves Data and Future Net Revenue Estimates".

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 16 of the Company's audited consolidated financial statements for the year ended December 31, 2018.

Future Development Costs

The Company expects to fund its future development costs by cash generated from operating activities, cash on hand and short and long-term debt. In addition, the Company has access to additional funding through credit facilities and the issuance of equity through shelf prospectuses, subject to market conditions. The cost associated with this funding 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, 2018:

	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)*
2019	1,846.4	2,007.5	327.0	327.0	55.9	83.1	2,229.3	2,417.6
2020	1,597.6	1,787.5	226.8	226.8	—	13.3	1,824.4	2,027.6
2021	1,245.3	1,377.6	—	—	—	—	1,245.3	1,377.6
2022	693.9	844.9	—	—	—	—	693.9	844.9
2023	689.9	839.3	—	—	—	—	689.9	839.3
Remaining	6,367.9	13,693.5	—	—	—	—	6,367.9	13,693.5
Total	**12,441.0**	**20,550.2**	**553.9**	**553.9**	**55.9**	**96.4**	**13,050.8**	**21,200.5**

Production Estimates

Yearly Production Estimates for 2019

	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	24.3	26.4	124.4	175.2	278.7	13.3	234.9
Total Gross Probable	5.6	2.1	7.1	14.9	35.7	2.1	22.9
Total Gross Proved Plus Probable	**30.0**	**28.5**	**131.5**	**190.0**	**314.4**	**15.4**	**257.9**
China							
Total Gross Proved	—	—	—	—	187.0	7.7	38.9
Total Gross Probable	—	—	—	—	1.2	0.1	0.3
Total Gross Proved Plus Probable	**—**	**—**	**—**	**—**	**188.1**	**7.8**	**39.1**
Indonesia							
Total Gross Proved	—	—	—	—	38.4	2.5	8.9
Total Gross Probable	—	—	—	—	—	0.1	0.1
Total Gross Proved Plus Probable	**—**	**—**	**—**	**—**	**38.4**	**2.6**	**9.0**
Total							
Total Gross Proved	24.3	26.4	124.4	175.2	504.0	23.5	282.7
Total Gross Probable	5.6	2.1	7.1	14.9	36.9	2.3	23.3
Total Gross Proved Plus Probable	**30.0**	**28.5**	**131.5**	**190.0**	**540.9**	**25.8**	**306.0**

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

Social and Environmental Considerations

Social and Environmental Policy

Husky has a Health, Safety and Environment Policy that affirms its commitment to operational integrity. Operational integrity at Husky means conducting all activities safely and reliably so that the public is protected, impact to the environment is minimized, the health and wellbeing of employees are safeguarded, contractors and customers are safe, and physical assets (such as facilities and equipment) are protected from damage or loss.

The Health, Safety and Environment Committee of the Board of Directors (the "HS&E Committee") is responsible for oversight of the Health, Safety and Environment Policy, oversight of audit results and monitoring compliance with the Company's environmental policies, key performance indicators and regulatory requirements. The mandate of the HS&E Committee is available in the Governance section of the Husky website at www.huskyenergy.com.

To reinforce the Health, Safety and Environment Policy, Husky holds an annual summit for leaders, attended by members of the HS&E Committee and led by the Chief Executive Officer. During the summit, CEO awards are presented for the initiatives that demonstrate the highest level of operational integrity. Guest and internal speakers present on pertinent issues and the latest developments in the fields of operational integrity and corporate responsibility.

Husky is committed to upholding high standards of business integrity and seeks to deter wrongdoing and promote transparent, honest and ethical behaviour in all its business dealings. The Company has a Code of Business Conduct that sets out the standards employees, contractors, officers and directors are expected to meet. The 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 of Business Conduct is available on the Husky website at www.huskyenergy.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 Company's Code of Business Conduct. 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, health, safety and environment, and human resources personnel.

Husky is committed to conducting business fairly, with integrity and in compliance with applicable laws. It has an Anti-Bribery & Anti-Corruption Policy to reinforce the Code of Business Conduct 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.

Husky is committed to conducting business ethically and legally. A key component of this commitment is to comply with competition laws, the purpose of which is to preserve and promote a competitive market. The Company's Competition Act Compliance Policy assists employees by providing relevant information about competition laws and guidelines to follow in order to ensure these laws are complied with and that any issues are handled appropriately.

Husky is an equal opportunity employer committed to an environment free of discrimination, harassment and violence and where respectful treatment is the norm. The 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 Community Investment Program that supports local charitable organizations. The Community Investment Policy provides guidance with the general goal of ensuring that contributions under the Community Investment Program are supported by a consistent and rigorous decision-making process and reflect Husky's core corporate values and business strategy.

Husky has an External Scholarships and Educational Support Policy that encourages advanced education by providing financial assistance to qualified students pursuing studies at several post-secondary educational institutions, reinforcing Husky's commitment to support the communities where it operates. The policy includes Husky's Scholarships for Aboriginal Students which assists Aboriginal people in achieving greater career success by encouraging them to pursue an advanced education.

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

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

Husky is committed to ensuring health and safety at work. The ability of every employee or 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, the Alcohol and Drug Policy outlines the standards and expectations associated with alcohol and other drug use, consistent with Husky's overall safety culture.

The above policies are available to employees and contractors on the Company's intranet. Communication of the policies is provided through direct e-mail and articles published on the Company's intranet. Mandatory training is 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's Operational Integrity Management System ("HOIMS") is a set of interrelated policies, aims, expectations and processes that provides a systematic way for the Company to identify, assess, and control health, safety and environmental ("HSE") hazards and associated risks. Additionally, HOIMS establishes standards and procedures integral to safe operations and protecting the environment. Strong leadership, with adherence to HOIMS, delivers on Husky's strategic operational integrity objectives and drives HSE performance.

The fundamental elements of HOIMS are:

Accountability

- All personnel demonstrate accountability for operational integrity.

Occupational Health & Safety

- Health and safety risks are effectively managed.

Risk Management

- All hazards are identified, analyzed, and evaluated and associated risks are managed.

Emergency Management

- Emergency response, business continuity, and security programs are implemented.
- Husky is prepared to manage an emergency, business interruption, or security event.

Reliability & Integrity

- Manage equipment and controls that are essential to reliability and integrity.

Training & Competency

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

Incident Management

- Investigate and learn from incidents to improve operational integrity performance.

Environmental Stewardship

- Responsibly manage our environmental impact.

Management of Change

- Permanent, temporary, and emergency changes that impact operational integrity, and the risks associated with those changes, are managed.

Information Management

- Operational integrity information is accurate and current.
- The right people can access the right information at the right time.

Regulatory Compliance

- Husky complies with regulatory requirements.

Project Delivery

- Facilities are designed and built, and assets are developed, to meet operational integrity aims and expectations of HOIMS.

Supply Chain

- Supplied services and materials meet Husky's operational integrity requirements.

Assurance & Improvement

- Learn from results to continually improve Husky's processes, procedures, competencies and operational integrity performance.

Pipeline Integrity

Husky implements a life cycle risk-based Pipeline Integrity Management ("PIM") program across all Husky owned and operated pipelines. The program is a framework that is supported by a suite of documents including but not limited to the Pipeline Operations and Maintenance Procedures Manual ("POMM"), which provides guidelines on the safe operation and maintenance of pipelines. Numerous processes are required and utilized throughout the pipeline lifecycle to ensure a proactive approach to managing the integrity, operations and maintenance of the pipelines.

Processes for the management of pipeline integrity include:

- Risk management program: used to identify the integrity threats throughout the pipeline's life cycle, and the risks associated with each threat. Appropriate measures are taken to address these risks and reduce them to as low a level as reasonably practicable.
- Geotechnical program: to identify, monitor and mitigate potential impacts to pipelines from natural earth movements.
- Engineering assessments: evaluate the fitness for service of pipelines when changes to design are made in order to proactively mitigate the risk to process safety.
- Failure investigations: establish root cause of any failures and apply the learnings to improve integrity programs.
- Annual pipeline integrity reviews: completed for all pipeline systems to review the effectiveness of integrity programs and where applicable make recommendations for improvement.
- Training: Husky has a Learning Management System ("LMS") which defines mandatory training requirements for all employees. Husky has a web-based PIM and POMM training program on LMS that is available for all employees involved in the operation and maintenance of pipelines.
- Performance targets (number of incidents/1,000 km of pipeline) are set annually. Targets are tracked quarterly by the pipeline steering committee and immediate steps are taken to address any deficiencies.
- PIM program sustainment and continuous improvement: a comprehensive self-assessment process is being implemented to ensure effective sustainment and the continuous improvement of the PIM program.
- PIM program review: regular review of the PIM program is completed to ensure it aligns with the latest code and regulatory requirements. The reviews also consider Husky experience and pipeline industry standards and practices.

Environmental Protection

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 regulations cover matters such as air emissions, wastewater discharge, 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. In addition to existing requirements, Husky recognizes that there are emerging regulatory frameworks that may have a financial impact on the Company's operations. See "Risk Factors" and "Industry Overview".

Directly and through joint venture partnerships, Husky is a member of several industry associations that collaborate to identify and implement best practices on environmental performance. The International Petroleum Industry Environmental Conservation Association ("IPIECA") produces guidelines that Husky uses to improve its operations and environmental practices, enhance its strategic planning and engage with regulators. In Canada, Husky is a member of both the upstream oil and gas industry association, the Canadian Association of Petroleum Producers ("CAPP"), and downstream industry association, the Canadian Fuels Association ("CFA"). Husky participates in technology research for energy efficiency and emissions reduction through membership and participation in the Petroleum Technology Alliance Canada ("PTAC") and the Clean Resource Innovation Network ("CRIN")..

As an active member of the In-situ Water Technology Development Centre, Husky is developing new technologies to reduce water use and improve energy efficiency. Husky dedicates teams 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, after it has been treated, from a nearby oil sands operation and lower quality non-saline groundwater that is in contact with bitumen to generate steam for oil recovery.

Ongoing remediation and reclamation work is occurring at approximately 3,000 well sites and facilities in western Canada. During 2018, Husky spent approximately $181 million on asset retirement obligations ("ARO") in North America, and the Company expects to spend approximately $202 million in 2019 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 ("AER") 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 their 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, 2018, the Company had deposited funds of $128 million, which was classified as non-current liabilities.

The Company 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 16 of the Company's 2018 audited consolidated financial statements.

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.

As part of the Company's review of proposed regulations that may affect its business and operations, the Company may, from time to time, prepare an internal analysis of the possible or expected impact of new regulations, which are subject to various uncertainties. It is not possible to predict with certainty the amount of additional investment in new or existing facilities required in the future for environmental protection or to address regulatory compliance requirements, such as reporting. Costs associated with levy payments for emerging climate change regulations may be significant. See "Risk Factors - Climate Change Regulations" for a description of the impact that climate change regulations may have on the Company.

INDUSTRY OVERVIEW

The operations of the oil and gas industry are governed by a number of laws and regulations mandated by multiple levels of government and regulatory authorities in Canada, the U.S. and other foreign jurisdictions. These laws and regulations, along with global economic conditions, have shaped the developing trends of the industry. The following discussion summarizes the trends, legislation and regulations that the Company believes have the most significant impact on the short and long-term operations of the oil and gas industry.

Crude Oil and Natural Gas Production

During the first half of 2018, certain members of the Organization of Petroleum Exporting Countries ("OPEC") and some key non-OPEC members voluntarily reduced production, which led to the increase of the global crude oil market benchmarks for the first half of 2018. However, towards the latter half of 2018, certain members of OPEC and some key non-OPEC members increased production as the global crude oil inventory decreased.

On December 7, 2018, OPEC and several non-OPEC members announced a production reduction of 1.2 mmbbls/day from their October 2018 production levels for six months beginning in January 2019. The cuts were in response to increasing evidence that oil markets could become oversupplied in 2019, which was evidenced in the recent price declines.[(1)]

In Canada, the western Canadian crude oil supply is forecasted to increase in the long term. In the Canadian Association of Petroleum Producers' ("CAPP") June 2018 publication, production in Canada was forecasted to increase from 4.2 mmbbls/day in 2017 to 6.2 mmbbls/day in 2035. The growth of Canada's crude oil industry depends on new pipelines and new policies.[(2)]

The Alberta government has set province-wide mandatory oil production cuts in an attempt to rebalance the market. This curtailment became effective January 1, 2019, and is expected to continue through the end of the year. The provincial government is targeting to reduce production by 325,000 bbls/day for the first quarter of 2019, before adjusting volume targets for the remainder of the year[(3)].

Total U.S. natural gas inventories were 19 percent lower at the end of November 2018 than the five-year (2013 – 2018) average for the end of November. Natural gas production is forecasted to grow in 2019 by approximately eight percent from 2018 volumes. [(1)]

(1) *"Short-Term Energy Outlook", December 2018, U.S. Energy Information Administration*
(2) *"Crude Oil Forecast, Markets and Transportation", June 2018, Canadian Association of Petroleum Producers*
(3) *"Protecting the value of our resources", December 2018, Alberta Government Website*

Commodity Pricing

Crude oil and natural gas producers negotiate purchase and sale contracts directly with respective buyers and these contracts are typically based on the prevailing market price of the commodity. The market price for crude oil is determined largely by global factors, and the contract price considers oil quality, transportation and other terms of the agreement. The price for natural gas in Canada is determined primarily by North America fundamentals because virtually all natural gas production in North America is consumed by North American customers, predominantly in the U.S. Commodity prices are based on supply and demand which may fluctuate due to market uncertainty and other factors beyond the control of entities operating in the industry.

Global crude oil benchmarks strengthened in the first half of 2018 due to market rebalancing, but weakened towards the end of the year due to record levels of oil production from the world's largest producers leading to increased global inventories, combined with uncertainties regarding future global demand. Furthermore, the WCS benchmark weakened towards the end of 2018 primarily due to an oversupply of Canadian crude oil resulting from continued transportation constraints. Consequently the WCS benchmark traded at a greater discount compared to other North American benchmarks. The price of West Texas Intermediate ("WTI") averaged US $64.77/bbl in 2018 compared to US$50.95/bbl in 2017. The price of Brent averaged US$70.97/bbl in 2018 compared to US$54.28/bbl in 2017. The price of WCS averaged US$38.46/bbl in 2018 compared to US$38.98/bbl in 2017.

In December of 2018, the Government of Alberta imposed an oil production curtailment order with the goal of raising the price of oil sold in Alberta during 2019.

Market Access(1)

The existing pipeline network servicing western Canada is operating at capacity and producers are relying more on rail to move incremental volumes. Pipelines are the preferred mode of transporting large volumes of crude oil for long distances over land, given the inherent economies of scale associated with pipelines.

In December of 2018, the Government of Alberta imposed an oil production curtailment order with the goal of raising the price of oil sold in Alberta during 2019. This reduced the economic motivation to export crude by rail or develop longer term market access strategies.

Currently, there is insufficient pipeline capacity originating in western Canada to transport crude oil out of the supply basin to meet the needs of producers. Both the Enbridge Mainline pipeline system and Trans Mountain pipeline continue to operate under apportionment, whereby the pipeline companies must reduce shippers' nominated volumes to derive an aggregate amount which can be transported by the pipeline in accordance with its available capacity.

Only three major pipeline projects remain under active development following the cancellation of TransCanada's Energy East pipeline project in October 2017. The combined capacity from Enbridge's Line 3 Replacement project, Trans Mountain Corporation's Trans Mountain Expansion, and TransCanada's Keystone XL would equal 1.79 mmbbls/day.

Existing pipeline infrastructure to transport crude oil production is at capacity and it is uncertain when additional pipeline capacity will become available.

(1) "Crude Oil Forecast, Markets and Transportation", June 2018, Canadian Association of Petroleum Producers.

Royalties, Incentives and Income Taxes

Canada

The amount of royalties payable on production from privately owned lands is negotiated between the mineral freehold owner and the lessee, and this production may also be subject to certain provincial taxes and royalties. Royalty rates for production from Crown lands are determined by provincial governments. When setting royalty rates, commodity prices, levels of production and operating and capital costs are considered. Royalties payable are generally calculated as a percentage of the value of gross production and generally depend on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery, depth of well and the type or quality of the petroleum product produced. Other royalties and royalty-like interests are, from time to time, carved out of the owner's working interest through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests or net carried interests.

Royalty rates as a percentage of gross revenues averaged eight percent in 2018 compared to seven percent in 2017. Royalty rates in Western Canada averaged nine percent in 2018, compared to seven percent in 2017, primarily due to higher WTI prices for the majority of 2018. Royalty rates in Atlantic averaged eight percent in 2018 compared to nine percent in 2017, primarily due to lower production combined with with higher eligible costs.

The Canadian federal corporate income tax rate was 15 percent in 2018 and 2017. Provincial rates ranged between 11 percent and 16 percent in both 2018 and 2017.

Other Jurisdictions

Royalty rates in Asia Pacific averaged seven percent in 2018, compared to six percent in 2017, primarily due to higher production from the BD Project which has higher royalty rates than the Liwan Gas Project.

Operations in the U.S. are subject to the U.S. federal tax rate of 21 percent and various state-level taxes. Operations in China are subject to the Chinese tax rate of 25 percent. Operations in Indonesia are subject to tax at a rate of 40 percent as governed by each project's PSC.

Land Tenure Regulation

In Canada, rights to natural resources are largely owned by the provincial and federal governments. Rights are granted to explore for and produce oil and natural gas subject to shared jurisdiction agreements, ELs, SDLs and production licences, leases, permits and provincial legislation which may include contingencies such as obligations to perform work or make payments.

For international jurisdictions, rights to natural resources are largely owned by national governments that grant rights in forms such as ELs and permits, production licences and PSCs. Companies in the oil and gas industry are subject to ongoing compliance with the regulatory requirements established by the relevant country for the right to explore, develop and produce petroleum and natural gas in that particular jurisdiction.

Environmental Regulations

General

Oil and 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 impose, among other things, restrictions, liabilities and obligations in connection with the generation, handling, storage, transportation, treatment and disposal of hazardous substances and waste and in connection with spills, releases and emissions of various substances to the environment, including emissions of greenhouse gases ("GHGs"). Environmental regulations also require that wells, facilities and other properties associated with Husky's operations 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 regulations, and impacts of possible changes, include:

- conventional air pollutant and GHG emission regulations and mandatory reductions in jurisdictions where the Company has operations.
- calculation and regulation of carbon intensity of fuels, including transportation fuels.
- fuel reformulation and substitution to support reduced GHG emissions.
- managing air pollutant emissions at equipment and facility levels with the general goal of ensuring compliance with increasingly more stringent ambient air quality standards and air pollutant regulations.
- potential for restrictive operating policies on development in areas of value to species at risk.
- increased restrictions on freshwater licensing and 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 and additional information requirements.
- 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.
- land use.
- measurement requirements for oil and gas operations.

Water

Numerous regulations are imposed on Husky'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.
- baseline domestic water well testing practices.
- 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. Husky has reporting requirements relating to most licensed freshwater withdrawals. Policies dictate water source selection and management. Water withdrawals are further governed by local watershed and/or industry water management plans.

Husky recognizes the importance of water security to the success of its operations and engages in dialogue on proposed regulatory changes, both directly and through industry associations. Husky believes it is sufficiently prepared to comply with new water regulations. 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 has realized financial impacts due to regulation changes. Proposed and future regulation changes could also have financial impacts.

Migratory Birds

Canada's oil and gas industry may affect migratory birds and bird habitat through land disturbance activities and operating practices (*e.g.*, sludge ponds). Industry activities risk contravening the *Migratory Bird Convention Act* (Canada) ("MBCA") and supporting legislation that prohibits the disturbance and destruction of migratory birds, their eggs and/or their nests. In 2016, the *Environmental Enforcement Act* (Canada) introduced a new fine regime that increased maximum fines up to $6 million, with all subsequent fines doubling, for corporations that are convicted under the MBCA. The Company's U.S. operations are subject to similar requirements pursuant to the *Migratory Bird Treaty Act*. The Company 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 the Company's permit from the Canadian Wildlife Service ("CWS"), the Company'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 the Company's Seabird Recovery Centre in consultation with CWS.

Air and Climate Change

General

The current regulatory environment related to air emissions and climate policy is dynamic. The impacts of emerging policy are becoming clearer as various jurisdictions finalize and implement new regulations. Husky engages in consultations for the design of proposed regulations and supports efforts to harmonize regulations across jurisdictions, both directly with regulators and through industry associations. Risk associated with these regulations is discussed under "Risk Factors".

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 emission performance standards and reporting.
- other regulatory measures including low carbon fuel and renewable fuel standards.

In 2017, Husky's gross Scope 1 GHG emissions were 11,180,000 tCO_2e. Scope 2 GHG emissions in that year were 2,221,000 tCO_2e. The Company uses an internal GHG management framework to guide the process of integrating climate change into its business strategy. Elements of the GHG management framework that inform corporate business strategy include GHG inventory and quantification, GHG reporting and verification, an emissions reduction strategy and a regulatory policy system.

In addition to climate policy risk, the industry faces physical risks attributable to a changing climate. Husky operates in some of the harshest environments in the world, including offshore NL. Climate change is expected to increase the frequency of severe weather conditions including winds, flooding and variable temperatures, which are contributing to the melting of northern ice and increased iceberg activity. The Company has several policies in place to protect people, equipment and the environment in the event of extreme weather conditions and adverse ice conditions.

Husky is managing physical risk through engineering for 1:100-year weather events. The Company's Atlantic business ice management program uses a range of resources, including a dedicated 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 commence in February 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. The Company also maintains a series of ad-hoc relationships with contractors, allowing the quick mobilization of additional resources as required.

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

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 percent below 2005 levels by 2030. Indonesia has pledged a 29 percent reduction below a "business as usual" baseline by 2030. China has pledged for total emissions to peak in 2030, but with reductions in emissions per unit GDP by 60-65 percent from 2005 levels.

There is a commitment to review and increase pledges every five years under the Paris Agreement.

On August 4, 2017, the U.S. submitted formal notice of intention to withdraw from the Paris Agreement; however, under the terms of the Paris Agreement, the U.S. will remain a party until approximately August 2020.

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

Canadian Federal Regulations

The Canadian federal government 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 five percent of their gasoline supply come from renewable sources (such as ethanol) and to have an average of at least two percent of their diesel supply come from renewable sources (such as bio-diesel).

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 tranche of the Multi-Sector Air Pollutants Regulations was published in June 2016. These regulations have included three BLIERs developed under AQMS for the cement sector, reciprocating spark-ignited natural gas engines and non-utility boilers and heaters in industrial sectors. An emissions guideline under the Canadian Environmental Protection Act 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. For example, a 'Code of Practice for the Management of Air Emissions from Pulp and Paper Facilities' was published in July 2018.

The BLIERs pertaining to nitrogen oxides ("NOx") emissions from boilers and heaters and NOx emissions from reciprocating engines in industrial facilities are applicable to the Company's Canadian upstream and downstream oil and gas facilities, with the exception of the Prince George Refinery since a sector-specific Refining BLIER will be developed separately for petroleum refineries. 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.

On October 23, 2018, the Government of Canada announced the federal carbon pricing system would be implemented in part or in whole in Saskatchewan, Manitoba, Ontario and New Brunswick in 2019 as an element of the Pan Canadian Framework on Clean Growth and Climate Change. The remaining provinces and territories either elected to adopt the federal carbon pricing system or presented provincial policies that were deemed equivalent by the federal government. The federal carbon policy has two key elements: a carbon levy applied to fossil fuels ($20 per tonne starting on April 1, 2019 and increasing by $10 annually to $50 per tonne in 2022); and an output-based pricing system for industrial facilities emitting GHGs above 50,000 tonnes per year.

On December 20, 2018, the Government of Canada published the Regulatory Proposal for the Output-Based Pricing System ("OBPS") Regulation under the Greenhouse Gas Pollution Pricing Act. The OBPS Regulatory Proposal includes draft sectorial Output-Based Standards, provisions pertaining to GHG emission quantification and reporting, as well as details on the administration process and content of verification reports. Stakeholder comments are accepted by February 15, 2019. Although final OBPS regulations will be published only in the summer of 2019, the regulatory requirements will be applied retroactively starting on January 1, 2019.

A federal Clean Fuel Standard ("CFS") Discussion Paper was also 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. Proposed regulations for liquid fuels are expected to be published in 2019. Consultations on the federal CFS are ongoing.

On December 20, 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 percent) by 2030 from a 2016 baseline. For liquid fuels, including transportation fuels, draft regulations are expected to be published in mid-2019 and final regulations in 2020 with coming into force in 2022. Stakeholder comments on the CFS Regulatory Design Paper are accepted by February 1, 2019, but CFS consultations will be ongoing.

The Government of Canada is committed to reducing methane emissions from the oil and gas sector by 40 percent to 45 percent below 2012 levels by 2025. Final methane reduction regulations for the upstream oil and gas industry were published on April 26, 2018. Emission 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 expected to come into force as early as 2020, and the remaining requirements by 2023.

Draft "Regulations Respecting Reduction in the Release of Volatile Organic Compounds (Petroleum Sector)" pertaining to the downstream oil and gas industry were published by the Government of Canada in May 2017. The regulations will require the implementation of comprehensive Leak Detection and Repair ("LDAR") programs at refineries, upgraders and certain petrochemical facilities. These facilities will also be required to monitor the levels of certain volatile organic compounds at facility perimeters. The final regulations are targeted for publication in June 2019, with the fenceline monitoring requirements expected to be implemented starting in 2020 and the enhanced LDAR requirements coming into force in 2021.

Canadian Provincial Greenhouse Gas Regulations

In 2015, Alberta announced a major shift in its climate regulations through its Climate Leadership Plan. It includes four key areas in which the Government of Alberta is moving forward:

- Phasing out emissions from coal-generated electricity and developing more renewable energy.
- Implementing a new carbon price on GHG emissions.
- A legislated oil sands emission limit.
- Employing a new methane emission reduction plan.

As of January 1, 2018, large final emitters ("LFEs"), *i.e.,* facilities that emit over 100,000 tonnes of CO_2e per year, fall under the Carbon Competitiveness Incentive Regulation ("CCIR") that employs output-based allocations to benchmark facilities against peers within the same industrial sector in the province. CCIR applies to Husky's Tucker and Sunrise facilities.

As of January 1, 2018, Alberta increased its broad-based carbon levy to $30 per tonne. Emissions from the combustion of produced fuel at upstream oil and gas facilities emitting less than 100,000 tonnes of CO_2e per year will be exempt from a fuel use levy until January 1, 2023, to allow time for these facilities to reduce methane emissions under provincial and federal methane regulations. Finally, total emissions from the oil sands will be capped at a maximum of 100 megatonnes in any year, with provisions for cogeneration and new upgrading capacity. The details of how this emissions limit will be implemented have not been finalized.

The AER is working collaboratively to develop and implement a regulatory framework that achieves the Government of Alberta's methane emissions reduction outcome of 45 percent by 2025. Alberta has announced that it intends to reduce methane emissions from oil and gas operations using the following approaches:

- Applying new emissions design standards to new Alberta facilities.
- Improving measurement and reporting of methane emissions, as well as leak detection and repair requirements.
- Developing a joint initiative on methane reduction and verification for existing facilities and backstopping this with regulated standards that take effect in 2020, with the general goal of ensuring the 2025 target is met.
- On December 13, 2018, the AER released final methane regulations which are effective January 1, 2020.

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 draft "The Management and Reduction of Greenhouse Gases Amendment Act", and various GHG regulations under the Act impose a carbon price (starting at $20 per tonne in 2019) on facilities that emit more than 25,000 tonnes of CO_2e/year. These would include the Upgrader and Husky's ethanol plant, and the Saskatchewan thermal plants. As part of the October 23, 2018 Government of Canada's announcement on climate policy equivalency, the Province of Saskatchewan will have a carbon tax applied to fuel for all facilities under that threshold, which would include Husky's Cold operations. Saskatchewan has launched a court case to challenge federal jurisdiction in imposing the carbon tax.

The Government of Saskatchewan has drafted the "Oil and Gas Emissions Management Regulations" that would 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 emission intensities for various regions within the province. The proposed regulations are intending to reduce provincial methane emission intensity by 45 percent by 2025.

In British Columbia, regulations established in 2008 target a provincial reduction in GHG emissions of at least 33 percent below 2007 levels by 2020 and 80 percent below 2007 levels by 2050. British Columbia had a $30 per tonne carbon tax from January 1 to March 31, 2018, which has been increased to $35 per tonne since April 1, 2018. Additionally, British Columbia has a Renewable and Low Carbon Fuel Requirements Regulation in place that requires a reduction in the allowable carbon intensities of transportation fuels, with penalties applied for intensities that do not meet targets.

The British Columbia government released its Climate Leadership Plan in August 2016. The 21 actions are targeted across major sectors of the economy, including annual reductions of up to five million tCO_2e by 2050 in the oil and gas sector through a focus on methane emissions, carbon capture and storage, and electrification. The British Columbia government has committed to increasing the provincial price on carbon by $5 per tonne annually (starting in April 2018) to $50 per tonne in 2021.

British Columbia released its Clean BC strategy on December 5, 2018, which is the first part of a longer-term strategy and aims to allow the province to reach 75% of its 2030 GHG reduction target. Over the next 18 to 24 months, it is expected that British Columbia will identify additional reductions to help the province meet or exceed the remaining 25% of its 2030 goal. A new round of stakeholder engagement is expected to begin in 2019 to inform the next steps of Clean BC that focuses on key actions in the transportation, building, waste management, and clean industry sectors.

To achieve cleaner transportation, by 2020 British Columbia will require automakers to meet an escalating annual percentage of new light-duty zero-emission vehicle sales. By 2040, all new light-duty cars and trucks sold in the province must run on clean electricity. After 2025, new vehicles will be subject to increasing tailpipe emissions standards. By 2030, fuel suppliers will be required to reduce the carbon intensity of diesel and gasoline by 20%. British Columbia will also work with renewable fuel providers to increase new production of renewable fuels by 2030, and the province will also implement a minimum requirement for 15% renewable content in natural gas by 2030.

To incentivize cleaner industry, the Government of British Columbia has signed a Memorandum of Understanding ("MOU") with the Business Council of British Columbia, setting out a framework to develop a low-carbon industrial strategy. The MOU commits both parties to keeping energy-intensive, trade-exposed industries competitive. The Clean BC strategy will also direct a portion of the carbon tax paid by industry into incentives for cleaner operations specifically designed for regulated large industrial operations.

The British Columbia Oil and Gas Commission is also developing regulations to reduce methane emissions in the upstream production of natural gas by 45% by 2025, and the province is planning to develop a regulatory framework for underground CO_2 storage for both the natural gas sector and direct air capture.

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 will apply in full in Manitoba. This will include the application of an output-based standard to the Company's Minnedosa ethanol plant.

On July 3, 2018, Ontario canceled its cap and trade program. As part of the October 23, 2018 announcement by the federal government, the federal carbon policy will apply in full in Ontario. Ontario has launched a court case to challenge federal jurisdiction to impose the federal carbon policy.

On June 7, 2016 the "Management of Greenhouse Gas Act" passed in the House of the Assembly of Newfoundland and Labrador, 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, 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 performance-based regulation imposes carbon pricing (beginning at $20/tonne in 2019) on petroleum production facilities with GHG emissions exceeding 25,000 tonnes/year and Mobile Offshore Drilling Units (MODUs) with GHG emissions exceeding 15,000 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. The 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.

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 "tailored" the Clean Air Act 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 GHGs. In June 2014, the U.S. Supreme Court invalidated portions of the 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.

The EPA has not yet issued proposed or final GHG emissions standards for new or existing refineries but could do so in the future. The EPA has, however, issued GHG standards for oil and gas production operations, including hydraulic fracturing and these or similar regulations could affect refineries by indirect impacts on crude oil supplies and costs. These and other EPA regulations regarding GHG emissions are generally subject to judicial challenges and could be modified by regulatory actions or new legislation.

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 of 2005 and expanded under the Energy Independence and Security Act 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 RVOs set in November 2018 for calendar year 2019 were substantially higher for cellulosic biofuel (418 million gallons compared to 288 million gallons) and were similar or somewhat higher for other renewable categories. It is possible that advocacy groups will challenge the RVOs with the goal of forcing the EPA to establish more stringent RVOs.

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

Abandonment Liability

The AER manages abandonment liability and the licence transfer process using the provisions of Directive 006: Licencee Liability Rating Program and Licence Transfer Process. Directive 006 is designed to prevent Alberta taxpayers from incurring costs to suspend, abandon, remediate and reclaim a well, facility or pipeline. Under the Licencee Liability Rating Program, each licencee is assigned a Liability Management Rating. The Liability Management Rating is the ratio of a licencee's eligible deemed assets under the Licencee Liability Rating Program, the Large Facility Liability Management Program and the Oilfield Waste Liability Program to its deemed liabilities in these programs. The Liability Management Rating assessment is designed to assess a licencee's ability to address its suspension, abandonment, remediation and reclamation liabilities. This assessment is conducted monthly and on receipt of a licence transfer application in which the licencee is the transferor or transferee.

If a licencee's deemed liabilities exceed its deemed assets, the licencee is required to post a security deposit with the AER to make up the shortfall. If a licencee fails to post security, if required, then the AER may take a number of steps to enforce these provisions, which include non-compliance fees, partial or full suspension of operations, suspension and/or cancellation of a permit, licence or approval and prevention of the transfer of licences held by licencees that do not meet the new requirements.

As a result of the Redwater Energy Corp. ("Redwater") bankruptcy court ruling released in May 2016, whereby the court found that receivers and trustees of AER licencees may selectively disclaim unprofitable assets (and their associated abandonment and reclamation obligations) under section 14.06 of the *Bankruptcy and Insolvency Act* (Canada), the AER and the Orphan Well Association developed regulatory measures to mitigate the liability impact of licencee's abandonment, reclamation and remediation obligations falling back to the industry.

Consequently, as of June 2016 a condition of transferring existing AER licences, approvals and permits requires transferees to demonstrate that they have a liability management ratio ("LMR") of 2.0 or higher immediately following the transfer. If the transfer of the licence does not improve the purchaser's LMR to 2.0 (or higher), the purchaser can post a security deposit, address existing abandonment obligations or transfer some of its assets.

Like the AER, the Government of Saskatchewan has established an LMR rating of 1.0 as its threshold for providing a deposit. If a licencee's LMR is less than 1.0, meaning the liability is greater than the deemed assets, that licencee will be required to submit a deposit to the Saskatchewan Ministry of Energy and Resources for the difference.

In response to the Redwater ruling, all licence transfer applications in Saskatchewan will be reviewed in detail, and the Ministry of Energy and Resources will consider relevant factors in calculating transfer deposit requirements. In addition to increased deposit requirements, The Ministry of Energy and Resources may incorporate additional conditions with licence transfer approvals which may impact the decision to proceed with certain transactions.

The Government of Saskatchewan intervened in the Alberta Court proceedings regarding Redwater's bankruptcy with the general goal of ensuring their views were fully considered by the courts. The Saskatchewan Ministry of Justice has indicated opposition to any attempt by a receiver in Saskatchewan to renounce uneconomic oil and gas assets which are subject to the LMR program in Saskatchewan. The Saskatchewan ministry has stated that licence transfer applications in Saskatchewan will be considered non-routine as the Saskatchewan ministry will not be strictly relying on the standard LMR calculations in evaluating deposit requirements.

In January 2019, the Supreme Court of Canada's ruling in Redwater was released, wherein the court held that abandonment and reclamation obligations of a debtor are binding on a Trustee, are not creditor claims nor claims provable in bankruptcy, and do not conflict with the general priority scheme in the *Bankruptcy and Insolvency Act* (Canada). The court ruled that the provincial regulatory regime can coexist with and apply alongside the *Bankruptcy and Insolvency Act* (Canada). The governments of Alberta and Saskatchewan have not yet made changes to the abandonment and reclamation obligations of licencees. Similarly, the Government of Canada has not yet made changes to the federal insolvency regime to account for the character and needs of Canada's natural resource industries.

Hydraulic Fracturing

Hydraulic fracturing is a method of increasing well production by injecting fluid under high pressure down a well to crack the hydrocarbon bearing rock. In the case of water-based fractures, the fluid typically consists of water, sand and a relatively small amount of chemicals. This mixture flows into the cracks where the sand remains to keep the cracks open and enable natural gas or liquids to be recovered. Fracturing is designed so that the fracturing fluids can be produced back to the surface through the wellbore and are stored for reuse or future disposal in accordance with provincial regulations. The wells are designed and installed to provide multiple barriers protecting fresh groundwater aquifers from the fracturing process.

The Government of Canada manages use of chemicals through its Chemical Management Plan and New Substances Program. Some provinces require the details of fracturing fluids to be submitted to regulators. In Alberta, the AER requires that all fracturing operations submit reports regarding the quantity of fluids and additives. For Alberta and British Columbia, the website www.FracFocus.ca provides the public with access to individual well summaries of the fluids and chemicals reported.

In response to concerns that hydraulic fracturing may induce seismic events, the AER has imposed requirements for seismic monitoring, mitigation response plans and reporting in select areas of the province.

Inter-wellbore communication during hydraulic fracturing operations is the transfer of pressure from the wellbore being stimulated to an adjacent offset well. This event is dependent on a number of factors such as distance between wells, type of fluid used and whether an energizer is being used during operations. AER Directive 83 and IRP 24 provide rules and guidelines addressing this concern.

Land Use

In 2012, the Government of Alberta approved the Lower Athabasca Regional Plan ("LARP"), which covers the lower Athabasca region and includes Husky's oil sands assets and major projects in the province. The LARP was developed to consider cumulative effects within the region using formal management frameworks for: Air Quality, Surface Water Quality and Quantity, Groundwater Management and Biodiversity.

The use of each framework establishes approaches with the general goal of ensuring trends are identified and assessed, regional limits are not exceeded, and air, water and biodiversity remain healthy for the region's residents and ecosystems during oil sands development. To date, the Biodiversity Framework under LARP has not been finalized.

The South Saskatchewan Regional Plan was approved by the Government of Alberta in 2014, and was subsequently amended in 2017, and covers the southern portion of Alberta, including some Husky Western Canada assets. The plan details Alberta's long-term commitment to conservation, protection of watersheds, sustaining biodiversity and sensitive habitats.

Industry Collaboration Initiatives

Husky participates in industry associations and sustainability groups to better understand environmental, safety and social issues while benefitting from, and contributing to, industry innovation and good management practices.

Through Husky's membership in Canada's upstream industry association, CAPP,and the Canadian Fuels Association, which represents Canada's refining and transportation fuels industry, and the American Fuels and Petrochemical Manufacturers which represents the U.S. refining and petrochemicals industry, the Company enhances its ability to identify and address potential policy and regulatory risks to its business and participates in advocacy related activity to reduce those risks. Husky participates on the CAPP Board of Governors, as well as various Executive Policy Groups and working level groups and committees that focus on areas of policy or regulation that have been identified as areas of interest or impact to Husky's business. Similarly, Husky participates in the Canadian Fuels Association Board of Directors, Strategy & Planning Group, as well as various resource groups and national committees.

Husky is a member of IPIECA, the global oil and gas industry association for environmental and social issues and is participating in its Water Task Force and Climate Change Working Group as well as other topic-focused groups. The Company is also a member of Oil Spill Response Limited, an international industry-owned cooperative whose objective is to respond effectively to oil spills wherever in the world they may occur.

Husky also collaborates on water and carbon management and risk mitigation through involvement in industry initiatives and committees. As a member of the joint-industry Water Technology Development Centre and other joint-industry projects, Husky is committed to developing technologies that will reduce water and energy use for in-situ thermal bitumen operations.

Husky holds memberships with, or participates in, the following sustainability groups and industry associations: Alberta Industrial Fire and Emergency Management Association; Allen County Environmental Citizen's Advisory Committee; Allen County Local Emergency Planning Committee; American Fuel and Petrochemical Manufacturers; Calgary Region Airshed Zone; CAAP; Canadian Brownfields Network; Canadian Fuels Association; Canadian Land Reclamation Association; Canadian Standards Association; Canadian Technical Asphalt Association; CDP; Center for Chemical Process Safety, an American Institute of Chemical Engineers Technological Community; China Offshore Environmental Services; China Offshore Oil Operation Safety Office Under Ministry of Emergency Management of the People's Republic of China; China's Marine Safety Administration; CHWMEG Inc.; Clean Resource Innovation Network; Clearwater Mutual Aid CO-OP; Conference Board of Canada - Council on Emergency Management; Devonian Aquifer Working Group - COSIA joint industry project; Earth Rangers; Eastern Canada Response Corporation; Edson Mutual Aid Committee; Emergency Response Assistance Canada; Energy Safety Canada; Environmental Services Association of Alberta; Environmental Studies Research Funds; Faster Forests - COSIA joint industry project; Foothills Research Institute - Grizzly Bear Program; Foothills Stream Crossing Partnership; Hardisty Mutual Aid Plan; Indonesian Petroleum Association; Industry Footprint Reduction Operations Group; International Oil & Gas Producers Association; Industrial Power Consumers Association of Alberta; IPIECA; Lakeland Industry and Community Association; Land Spill Emergency Program; Lima Area Security and Emergency Response Task Force; Lloydminster Emergency Preparedness Stakeholder Group; Mackenzie Delta Spill Response Corporation ; Ministry of Ecology and Environment of the People's Republic of China; Monitoring Avian Productivity and Survivorship; Monitoring Priority Area - COSIA joint industry project; Mutual Aid Alberta; Natural Sciences and Engineering Research Council FlareNet Network; North Saskatchewan Watershed Alliance; Ohio Chemistry Technology Council; Ohio Manufacturer's Association; Oil Sand Monitoring; Oil Spill Response Limited; One Ocean; Orphan Well Association; Ottawa River Coalition; Parkland Airshed Management Zone; Petroleum Research Newfoundland and Labrador; Petroleum Technology Alliance Canada; Prince George Air Improvement Roundtable; Prince George Industrial Mutual Aid Committee; Red Deer Air Quality Advisory Group (formerly PM 2.5 Response Advisory Committee); RM Wood Buffalo Mutual Aid Group; Saskatchewan Environmental Industry and Managers Association; Saskatchewan Industrial Energy Consumers Association; Saskatchewan Petroleum Industry Government Environmental Committee; Shawnee Industrial Neighbors Group; Strathcona District Mutual Assistance Emergency Response Assistance; Agreement; Superior Petroleum Partners; Transportation Community Awareness and Emergency Response; Water Technology Development Centre - COSIA joint industry project; Well Abandonment and Integrity Society; Western Canada Marine Response Corporation; Western Canadian Spill Services; Western Yellowhead Air Management Zone; Wood Buffalo Environmental Association.

RISK FACTORS

The following summarizes what Husky believes to be the most significant risks relating to its operations which should be considered when purchasing securities of Husky. Husky 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 of Directors.

Operational, Environmental and Safety Incidents

The Company's businesses are subject to inherent operational risks with respect to safety and the environment that require continuous vigilance. The Company seeks to minimize these operational risks by designing and building its facilities and conducting its operations in a safe and reliable manner using HOIMS, an integrated management system that considers environmental requirements as well as process and occupational safety. Failure to manage the risks effectively could result in potential fatalities, serious injury, interruptions to activities or use of assets, damage to assets, environmental impact or loss of licence to operate. Enterprise risk management, emergency preparedness, business continuity and security policies and programs are in place for all operating areas and are adhered to on an ongoing basis. 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 natural gas production. Lower prices for crude oil, NGL and 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 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 heavy crude oil and bitumen is limited and planned increases of North American heavy crude oil and bitumen production may create the need for additional heavy oil and bitumen 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 a number of 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 natural gas production is currently located in Western Canada and Asia Pacific. Western Canada's natural gas production is subject to North American market forces. North American natural gas supply and demand is affected by a number of factors including, but not limited to, the amount of 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.

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 natural gas.

The fluctuations in refined products, crude oil and 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.

Reservoir Performance 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, investor confidence and the Company's ability to deliver on its growth strategy.

In order to maintain the Company's future production of crude oil, 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. To mitigate the effects of this, the Company must undertake successful exploration and development programs, increase the recovery factor from existing properties through applied technology and identify and execute strategic acquisitions of proved developed and undeveloped properties and unproved prospects. 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.

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. With growing oil production across North America and the limited availability of infrastructure to carry the Company's products to the marketplace, oil and natural gas transportation capacity is expected to 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.

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 activist 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.

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.

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.

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, 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.

Partner Misalignment

Joint venture partners operate 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.

Reserves Data, Future Net Revenue and Resource Estimates

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 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 percent of the future net revenue discounted at 10 percent 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. Inaccurate appraisal of large project reservoirs could result in missed production, revenue and earnings targets and could have a material adverse effect on the Company's reputation, investor confidence and ability to deliver on its growth business strategy.

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, development or exploratory activities. As these governments continually balance competing demands from different interest groups 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 Regulation

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, formulation or demand of products, which may or may not be offset through market pricing.

The Company anticipates further changes in environmental legislation could occur, which may result in stricter standards and enforcement, larger fines and liabilities, increased compliance costs and approval delays for critical licences and permits. See "Industry Overview – Environmental Regulations".

Climate Change Regulation

Climate change regulations may become more onerous over time as governments implement policies to further reduce GHG emissions. As part of long range planning, the Company assesses future compliance costs associated with regulations of GHG emissions in its operations and the evaluation of future projects, based on the Company's outlook for carbon pricing under current and pending regulations. The impact of recently announced regulations is being evaluated as provinces and the federal government finalize carbon pricing regulations. 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. The Company continues to monitor 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 the Company operates.

The Alberta Climate Leadership Plan began to be implemented in 2017. This plan includes an economy-wide carbon levy, rising to $30 per tonne in 2018 which applies to the Lloydminster Refinery, as well as a Carbon Competitiveness Incentive Regulation ("CCIR") that manages emissions at LFEs including the Tucker Thermal Project and Sunrise Energy Project. Under the previous Specified Gas Emitters Regulation, which expired at the end of 2017, the Tucker Thermal Project generated over 500,000 tonnes of credits due to improved emission intensity performance. These credits are eligible to offset future compliance obligations under the CCIR. See "Industry Overview – Air and Climate Change – Canadian Provincial Greenhouse Gas Regulations". These regulations are not anticipated to have a material impact over the duration of the Company's five-year long-range plan. The CCIR is due for review in 2020, along with the federal carbon policy. Uncertainty regarding future regulations, including carbon price and the details of implementing the oil sands emission limit, make it difficult to predict the potential future impact on the Company.

In December 2017, the Government of Saskatchewan released "Prairie Resilience" a policy paper on climate change strategy in which it outlines multiple commitments across five areas designed to make Saskatchewan more resilient to the climatic, economic and policy impacts of climate change. As part of this strategy, the government developed output-based performance standards for large industrial emitters and a Climate Resilience Measurement Framework. The large industrial emitters regulations will apply to the Company's Lloydminster Upgrader and ethanol plant and Saskatchewan thermal projects to reduce emissions while considering the economic competitiveness of these sectors. The smaller facilities (emitting under 25,000 tonnes/year) will be exposed to the federal carbon levy. The cost impacts of this levy on the Company's cold heavy oil production may be measurable. See "Industry Overview - Air and Climate Change - Canadian Provincial Greenhouse Gas Regulations".

The cost of compliance with British Columbia's $35 per tonne carbon tax (increasing to $40 on April 1, 2019) and the Renewable and Low Carbon Fuel Requirements Regulation may materially adversely affect the Company's Prince George Refinery. Additionally, future regulations in support of British Columbia's commitment under its Climate Leadership Plan are uncertain. See "Industry Overview – Air and Climate Change – Canadian Provincial Greenhouse Gas Regulations".

The application of the federal carbon policy in Manitoba may significantly adversely affect the Company's Minnedosa ethanol plant in Manitoba. See "Industry Overview – Air and Climate Change – Canadian Provincial Greenhouse Gas Regulations".

The Newfoundland and Labrador performance-based regulation imposes a carbon price beginning at $20/tonne in 2019 and escalating to $50/tonne in 2022. The provincial Gasoline and Diesel Tax begins at $20/tonne and will be adjusted with a goal of Atlantic parity related to provincial taxation (including carbon tax) of fuel products. The carbon tax rates will only increase to match equivalent increases in carbon taxation programs in neighbouring 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 the Company's Atlantic region operation.

Within the mandate of the Pan-Canadian Framework on Clean Growth and Climate Change, in May 2017, the Government of Canada released a technical paper on the federal carbon policy introducing two key elements: a carbon levy applied to gas that the Company uses at its facilities as well as retail fuel ($20 per tonne starting in 2019 and increasing by $10 annually to $50 per tonne in 2022), and an output-based pricing system for industrial facilities emitting GHGs above 50,000 tonnes of CO_2e per year. In December 2018, the Government of Canada published the Regulatory Design Paper on the CFS that focuses on the liquid fuel stream regulations. Draft CFS regulations are expected to be published in mid-2019 and final regulations in 2020, with the regulations expected to come into force in 2022. The impact of the CFS is still uncertain.

The Company's U.S. refining business may be materially adversely affected by the implementation of the EPA'sclimate change rules or, by future U.S. GHG legislation that applies to the oil and gas industry or the consumption of petroleum products and by other U.S. climate change statutes at the federal or state level or by regulations imposed by other federal agencies or 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 emission 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 and results of operations.

The U.S. 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. See "Industry Overview - Air and Climate Change - U.S. Renewable Fuels Standard". Due to regulatory uncertainty and in part due to the U.S. fuel supply reaching the "blend wall" (the 10 percent limit prescribed by most automobile warranties), the price and availability of RINs have been volatile.

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. 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.

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 govern the Company's credit portfolio and limit 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 including: cash and cash equivalents, cash from operating activities, undrawn credit facilities and capacity to raise capital from various debt and equity capital markets under its shelf prospectuses. The availability of capital under its shelf prospectuses is dependent on market conditions at the time of sale.

Debt Covenants

The Company's credit facilities include financial covenants, which contain a debt to capital 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.

Climatic Conditions

Extreme climatic conditions may 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. The Company has in place a number of policies to protect people, equipment and the environment in the event of extreme weather conditions and ice melt conditions.

The Company's Atlantic operations have a robust ice management program, which uses a range of resources including a dedicated 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 commence in February 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. The Company also maintains a series of ad-hoc relationships with contractors, allowing the quick mobilization of additional resources as required. The Company regularly assesses all aspects of its ice management program in order 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. The Company 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. The Company 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.

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.

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 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. The Audit Committee of the Company's Board of Directors has oversight of the Company's risk mitigation strategies related to cybersecurity.

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. There is a risk that the Company may have difficulty attracting and retaining personnel with the required skill levels. 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.

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 Husky 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.

HUSKY EMPLOYEES

The number of Husky's permanent employees was as follows:

	As at December 31,		
	2018	2017	2016
Number of permanent employees	**5,157**	5,152	5,150

DIVIDENDS

Dividend Amounts

The following table shows the aggregate amount of the dividends declared payable per share in respect of its last three 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:

	2018	2017	2016
Dividends per Common Share	**$ 0.450**	$ 0.075	$ —
Dividends per Series 1 Preferred Share	**$ 0.60**	$ 0.60	$ 0.73
Dividends per Series 2 Preferred Share	**$ 0.74**	$ 0.57	$ 0.42
Dividends per Series 3 Preferred Share	**$ 1.13**	$ 1.13	$ 1.13
Dividends per Series 5 Preferred Share	**$ 1.13**	$ 1.13	$ 1.13
Dividends per Series 7 Preferred Share	**$ 1.15**	$ 1.15	$ 1.15

Dividend Policy and Restrictions

The declaration and payment of dividends are at the discretion of the Board of Directors, 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 *Business Corporations Act* (Alberta) and other relevant factors.

Common Share Dividends

On February 28, 2018, the Board of Directors reinstated the quarterly Common Share cash dividend of $0.075 per share. On July 26, 2018, the Board of Directors increased the quarterly Common Share cash dividend to $0.125 per share.

The Board of Directors has the ability to declare dividends in common shares or in cash. Quarterly dividends are declared in an amount expressed in dollars per common share and can be paid by way of issuance of a fraction of a common share per outstanding common share determined by dividing the dollar amount of the dividend by the volume weighted average trading price of the common shares on the principal stock exchange on which the common shares are traded. The volume weighted average trading price of the common shares is calculated by dividing the total value by the total volume of common shares traded over the five-trading-day period immediately prior to the payment date of the dividend on the common shares.

The Company's dividend policy is reviewed on a regular basis and there can be no assurance that dividends will be declared or the amount of any future dividends.

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 percent annually for the initial period ending March 31, 2016, as and when declared by the Board of Directors. Thereafter, the dividend rate will be reset every five years at a rate equal to the five-year Government of Canada bond yield plus 1.73 percent. 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 who retained their shares will receive the new fixed rate quarterly dividend applicable to the Series 1 Preferred Shares of 2.404 percent 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 are 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 percent as and when declared by the Board of Directors. Effective March 31, 2016, Husky Energy 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 condition, on March 31, 2021, and on March 31every five years thereafter as long as the shares remain outstanding.

Series 3 Preferred Share Dividends

Holders of the Series 3 Shares are 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 percent annually for the initial period ending December 31, 2019 as declared by the Board of Directors. Thereafter, the dividend rate will be reset every five years at the rate equal to the five-year Government of Canada bond yield plus 3.13 percent. Holders of Series 3 Shares will have the right, at their option, to convert their shares into Series 4 Preferred Shares, subject to certain conditions, on December 31, 2019 and on December 31 every five years thereafter. Holders of the Series 4 Preferred Shares will be entitled to receive cumulative quarterly floating dividends at a rate equal to the 90-day Government of Canada Treasury Bill yield plus 3.13 percent.

Series 5 Preferred Share Dividends

Holders of the Series 5 Preferred Shares are 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 percent annually for the initial period ending March 31, 2020 as declared by the Board of Directors. Thereafter, the dividend rate will be reset every five years at the rate equal to the five-year Government of Canada bond yield plus 3.57 percent. Holders of Series 5 Preferred Shares will have the right, at their option, to convert their shares into Series 6 Preferred Shares, subject to certain conditions, on March 31, 2020 and on March 31 every five years thereafter. Holders of the Series 6 Preferred Shares will be entitled to receive cumulative quarterly floating dividends at a rate equal to the 90-day Government of Canada Treasury Bill yield plus 3.57 percent.

Series 7 Preferred Share Dividends

Holders of the Series 7 Preferred Shares are entitled to receive a cumulative fixed dividend, payable on the last day of March, June, September and December in each year, of 4.60 percent annually for the initial period ending June 30, 2020 as declared by the Board of Directors. Thereafter, the dividend rate will be reset every five years at the rate equal to the five-year Government of Canada bond yield plus 3.52 percent. Holders of the Series 7 Preferred Shares will have 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. Holders of the Series 8 Preferred Shares will be entitled to receive cumulative quarterly floating dividends at a rate equal to the 90-day Government of Canada Treasury Bill yield plus 3.52 percent.

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 of Directors 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.

If the Board of Directors declares a dividend on the common shares payable in whole or in part as a stock dividend, unless otherwise determined by the Board of Directors of Husky in respect of a particular dividend, the value of the common shares for purposes of each stock dividend declared by the Board of Directors of Husky shall be deemed to be the volume weighted average trading price of the common shares on the principal stock exchange on which the common shares are traded, calculated by dividing the total value by the total volume of common shares traded over the five trading day period immediately prior to the payment date of the dividend on the common shares.

In the event the stock dividend is to be issued pursuant to Husky's Stock Dividend Program, shareholders of record wishing to accept a payment of the stock dividend, and of future stock dividends declared by the Board of Directors in the form of common shares pursuant to Husky's Stock Dividend Program, are required to complete and deliver to Husky's transfer agent a Stock Dividend Confirmation Notice at least five business days prior to the record date of a declared dividend. The Stock Dividend Confirmation Notice permits shareholders to confirm that they will accept common shares as payment of the dividend on all or a stated number of their common shares. A Stock Dividend Confirmation Notice will remain in effect for all stock dividends on the common shares to which it relates and which are held by the shareholder unless the shareholder delivers a revocation notice to Husky's transfer agent, in which case the Stock Dividend Confirmation Notice will not be effective for any dividends having a declaration date that is more than five business days following receipt of the revocation notice by Husky's transfer agent. In the event a shareholder fails to deliver a Stock Dividend Confirmation Notice at least five business days prior to the record date of a declared dividend, or delivers a Stock Dividend Confirmation Notice confirming that the holder of common shares accepts the common shares as payment of the dividend on some but not all of the holder's common shares, the dividend on common shares for which no Stock Dividend Confirmation Notice was delivered or the dividend on those of the holder's common shares in respect of which the holder did not deliver a Stock Dividend Confirmation Notice, will be paid in cash. See "Dividends - Dividend Policy and Restrictions - Common Share Dividends".

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 of Directors 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 are entitled to vote, except in accordance with the provisions of the *Business Corporations Act* (Alberta).

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, 2019 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, 2020 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, 2020 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.

	Standard and Poor's Rating Services ("S&P")	Moody's Investor Service ("Moody's")	Dominion Bond Rating Services Limited ("DBRS")
Outlook/Trend	Stable	Stable	Stable
Senior Unsecured Debt	BBB	Baa2	A(low)
Series 1 Preferred Shares	P-3(high)		Pfd-2(low)
Series 2 Preferred Shares	P-3(high)		Pfd-2(low)
Series 3 Preferred Shares	P-3(high)		Pfd-2(low)
Series 5 Preferred Shares	P-3(high)		Pfd-2(low)
Series 7 Preferred Shares	P-3(high)		Pfd-2(low)
Commercial Paper			R-1(low)

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 pays a fee to credit rating agencies in order to receive a rating for debt or equity instruments upon issuance.

Moody's

Moody's long-term credit ratings are on a rating scale that ranges from Aaa (highest) to C (lowest). A rating of Baa2 by Moody's is within the fourth highest of nine categories and is assigned to debt securities which are considered medium-grade (i.e., they are subject to moderate credit risk). Such debt securities 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 1 indicates that the issue ranks in the higher end of its generic rating category, the modifier 2 indicates a mid-range ranking and the modifier 3 indicates a ranking in the lower end of that generic rating category.

S&P

Standard and Poor's long-term credit ratings are on a rating scale that ranges from AAA (highest) to D (lowest). 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. The addition of a plus (+) or minus (-) designation after a rating indicates the relative standing within the major rating categories.

S&P began rating Husky's Series 1 Preferred Shares and Series 2 Preferred Shares, Series 3 Preferred Shares, Series 5 Preferred Shares and Series 7 Preferred Shares on its Canadian preferred share scale on March 18, 2011, December 9, 2014, March 12, 2015 and June 17, 2015, respectively. Preferred share ratings are a forward-looking opinion about the creditworthiness of an issuer with respect to a specific preferred share obligation. There is a direct correspondence between the ratings assigned on the preferred share scale and S&P's ratings scale for long-term credit ratings. According to S&P's ratings system, a P-3 (high) rating on the Canadian preferred share rating scale is equivalent to a BB+ rating on the long-term credit rating scale. A rating of BB by S&P is within the fifth highest of 10 categories and indicates that the obligation is less vulnerable to nonpayment than other speculative issues. However, it faces major ongoing uncertainties or exposure to adverse business, financial, or economic conditions that could lead to the obligor's inadequate capacity to meet its financial commitments on the issue.

DBRS

Dominion Bond Rating Service's long-term credit ratings are on a rating scale that ranges from AAA (highest) to D (lowest). A rating of A (low) by DBRS is within the third highest of 10 categories and is assigned to debt securities considered to be of good credit quality. The capacity for payment of financial obligations is substantial, but of lesser credit quality than that of higher rated securities. Entities in the A category may be vulnerable to future events, but qualifying negative factors are considered manageable. The assignment of a "(high)" or "(low)" modifier within each rating category indicates relative standing within such category.

DBRS began rating Husky's Series 1 Preferred Shares and Series 2 Preferred Shares, Series 3 Preferred Shares, Series 5 Preferred Shares and Series 7 Preferred Shares on its Canadian preferred share scale on March 18, 2011, December 9, 2014, March 12, 2015 and June 17, 2015, respectively. Preferred share ratings are meant to give an indication of the risk that an issuer will not fulfill its full obligations in a timely manner, with respect to both dividend and principal commitments. DBRS preferred share ratings range from Pdf-1 (highest) to D (lowest). According to the DBRS' ratings system, preferred shares rated Pfd-2 are of satisfactory credit quality where protection of dividends and principal is still substantial, but earnings, the balance sheet and coverage ratios are not as strong as Pfd-1 rated companies.

DBRS began rating Husky's commercial paper on September 4, 2014. Credit ratings on commercial paper are on a short-term debt rating scale that ranges from R-1 (high) to D1 representing the range of such securities rated from highest to lowest qualify. A rating of R-1 (low) by DBRS is the third highest of 10 categories and is assigned to debt securities considered to be of good credit quality. The capacity for the payment of short-term financial obligations as they become due is substantial with overall strength not as favourable as higher rating categories. Entities in this category may be vulnerable to future events, but qualifying negative factors are considered manageable. The R-1 and R-2 commercial paper categories are denoted by (high), (middle) and (low) designations.

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 are listed and posted for trading on the Toronto Stock Exchange ("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.

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, 2018:

	High	Low	Volume (000's)
January	19.24	17.49	26,660
February	18.33	16.05	24,093
March	18.46	16.56	26,184
April	19.94	17.31	26,173
May	19.73	17.71	25,935
June	21.02	18.45	22,402
July	22.15	19.85	17,188
August	22.43	21.10	20,108
September	22.99	21.04	18,742
October	21.49	18.05	45,929
November	19.05	15.30	37,743
December	17.11	13.33	40,316

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, 2018:

	High	Low	Volume (000's)
January	18.48	17.37	131
February	18.30	17.75	167
March	18.25	17.55	119
April	17.87	17.44	124
May	18.30	17.45	37
June	17.59	17.15	56
July	18.21	17.56	104
August	18.26	17.70	127
September	17.81	17.60	71
October	17.91	16.00	79
November	17.09	14.30	453
December	14.70	12.15	235

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, 2018:

	High	Low	Volume (000's)
January	19.00	17.64	26
February	18.87	18.15	18
March	18.75	18.12	12
April	18.43	17.91	8
May	18.75	18.05	12
June	18.00	17.67	10
July	18.55	17.83	1
August	18.65	18.10	9
September	18.70	18.29	17
October	18.97	17.12	39
November	18.16	15.49	22
December	15.56	12.99	48

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, 2018:

	High	Low	Volume *(000's)*
January	25.63	24.44	111
February	25.19	24.69	294
March	25.22	24.66	136
April	24.81	24.29	209
May	25.05	24.41	52
June	25.00	24.55	61
July	25.27	24.96	121
August	25.23	24.88	70
September	25.00	24.69	135
October	24.97	21.88	142
November	23.87	20.02	112
December	20.50	16.40	212

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, 2018:

	High	Low	Volume *(000's)*
January	25.56	24.90	89
February	25.33	24.88	65
March	25.35	24.80	111
April	25.00	24.76	145
May	25.53	24.91	59
June	25.23	24.89	180
July	25.43	25.15	39
August	25.59	25.18	78
September	25.43	25.06	56
October	25.48	23.46	124
November	24.44	21.10	77
December	21.49	17.50	119

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, 2018:

	High	Low	Volume *(000's)*
January	25.70	25.00	63
February	25.36	24.86	60
March	25.36	24.90	72
April	25.31	24.86	111
May	26.07	25.03	204
June	25.24	24.83	74
July	25.39	24.98	32
August	25.50	25.10	152
September	25.45	25.03	42
October	25.39	23.19	164
November	24.40	20.88	74
December	22.14	17.55	186

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.

Name & Residence	Office or Position	Principal Occupation During Past Five Years
Li, Victor T. K. Hong Kong Special Administrative Region	Co-Chair of the Board Director since August 2000	Mr. Li is the Group Co-Managing Director of CK Hutchison Holdings Limited. He is also the Chairman and Managing Director of CK Asset Holdings Limited. He is also the Chairman and Executive Director of CK Infrastructure Holdings Limited and CK Life Sciences Int'l., (Holdings) Inc., a Non-Executive Director of Power Assets Holdings Limited and HK Electric Investments Manager Limited which is the trustee-manager of HK Electric Investments, and a Non-Executive Director and the Deputy Chairman of HK Electric Investments Limited. Mr. Li is also the Deputy Chairman of Li Ka Shing Foundation Limited, Li Ka Shing (Overseas) Foundation and Li Ka Shing (Canada) Foundation, and a Non-Executive Director of The Hongkong and Shanghai Banking Corporation Limited. Mr. Li serves as a member of the Standing Committee of the 12th National Committee of the Chinese People's Political Consultative Conference of the People's Republic of China. He is also a member of the Chief Executive's Council of Advisors on Innovation and Strategic Development of the Hong Kong Specia Administrative Region and Vice Chairman of the Hong Kong General Chamber of Commerce. Mr. Li is the Honorary Consul of Barbados in Hong Kong. Mr. Li holds a Bachelor of Science degree in Civil Engineering and a Master of Science degree in Civil Engineering, both received from Stanford University in 1987. He obtained an honorary degree, Doctor of Laws, honoris causa (LL.D.) from The University of Western Ontario in 2009.
Fok, Canning K. N. Hong Kong Special Administrative Region	Co-Chair of the Board and Chair of the Compensation Committee Director since August 2000	Mr. Fok is an Executive Director and Group Co-Managing Director of CK Hutchison Holdings Limited. 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. 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.

Bradley, Stephen E. Hong Kong Special Administrative Region	Member of the Audit Committee and the Corporate Governance Committee Director since July 2010	Mr. Bradley is a Director of Broadlea Group Ltd., Senior Consultant, NEX (formerly known as ICAP (Asia Pacific) Ltd.) and a Director of Swire Properties Ltd. (Hong Kong). Mr. Bradley entered the British Diplomatic Service in 1981 and served in various capacities including Director of Trade & Investment Promotions (Paris) from 1999 to 2002; Minister, Deputy Head of Mission & Consul-General (Beijing) from 2002 to 2003 and HM Consul-General (Hong Kong) from 2003 to 2008. Mr. Bradley also worked in the private sector as Marketing Director, Guinness Peat Aviation (Asia) from 1987 to 1988 and Associate Director, Lloyd George Investment Management (now part of BMO Global Asset Management) from 1993 to 1995. Mr. Bradley retired from the Diplomatic Service in 2009. Mr. Bradley obtained a Bachelor of Arts degree from Balliol College, Oxford University in 1980 and a post-graduate diploma from Fudan University, Shanghai in 1981. Mr. Bradley is a Member of the Hong Kong Securities and Investment Institute and an ICD.D with the Institute of Corporate Directors of Canada.
Ghosh, Asim London, United Kingdom	Director since May 2009	Mr. Ghosh has been on the Board of Directors of Husky Energy since May 2009 and was President & Chief Executive Officer from June 2010 until his retirement in December 2016. He is the former Managing Director and Chief Executive Officer of Vodafone Essar Limited. Under his leadership the cellular phone company grew from a virtual startup in 1998 to become one of the largest mobile companies in the world by subscribers. Mr. Ghosh started his career with Procter & Gamble in Canada and subsequently became a Senior Vice President of Carling O'Keefe. He later became founding co-Chief Executive Officer of Pepsi Food's start up operations in India. He served in senior executive positions and as Chief Executive Officer of the AS Watson consumer packaged goods subsidiary of Hutchison Whampoa. From 1991 to 1998 he managed a group of 13 business units, and expanded the group's operations from Hong Kong to China and Europe. Mr. Ghosh received his Master of Business Administration from Wharton School at the University of Pennsylvania, and obtained his undergraduate degree in Electrical Engineering from the Indian Institute of Technology.
Glynn, Martin J. G. British Columbia, Canada	Chair of the Corporate Governance Committee and a Member of the Compensation Committee Director since August 2000	Mr. Glynn is a Director and Chair of Public Sector Pension Investment Board (PSP Investments), and a Director of Sun Life Financial Inc. and Sun Life Assurance Company of Canada. Mr. Glynn was a Director from 2000 to 2006 and President and Chief Executive Officer of HSBC Bank USA N.A. from 2003 until his retirement in 2006. Mr. Glynn was a Director of HSBC Bank Canada from 1999 to 2006 and President and Chief Executive Officer from 1999 to 2003. Mr. Glynn obtained a Bachelor of Arts (Honours) degree from Carleton University, Canada in 1974 and a Master's degree in Business Administration from the University of British Columbia in 1976.

Koh, Poh Chan Hong Kong Special Administrative Region	Director since August 2000	Ms. Koh is Finance Director of Harbour Plaza Hotel Management (International) Ltd. (a hotel management company) and also a Member of the Executive Committee of CK Asset Holdings Limited. Ms. Koh is qualified as a Fellow Member (FCA) of the Institute of Chartered Accountants in England and Wales and is an Associate of the Canadian Institute of Chartered Accountants (CPA, CA) and the Chartered Institute of Taxation in the U.K. (CTA). Ms. Koh graduated from the London School of Accountancy in 1971 and was admitted to the Institute of Chartered Accountants in England and Wales in 1973, to the Chartered Institute of Taxation in the UK in 1976 as well as the Institute of Chartered Accountants of Ontario, Canada in 1980.
Kwok, Eva L. British Columbia, Canada	Member of the Compensation Committee and the Corporate Governance Committee	Mrs. Kwok is Chairman, a Director and Chief Executive Officer of Amara Holdings Inc. (a private investment holding company). Mrs. Kwok is also a Director of CK Life Sciences Int'l., (Holdings) Inc. and CK Infrastucture Holdings Limited. Mrs. Kwok is also a Director of the Li Ka Shing (Canada) Foundation.
	Director since August 2000	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. Mrs. Kwok obtained a Master's degree in Science from the University of London in 1967.
Kwok, Stanley T. L. British Columbia, Canada	Chair of the Health, Safety and Environment Committee	Mr. Kwok is a Director and President of Amara Holdings Inc. He is an independent Non-Executive Director of CK Hutchison Holdings Limited.
	Director since August 2000	Mr. Kwok is a Director of Element Lifestyle Retirement Inc. He retired as a Director of the CTBC Bank of Canada in July, 2017. Mr. Kwok obtained a Bachelor of Science degree (Architecture) from St. John's University, Shanghai in 1949, and an A.A. Diploma from the Architectural Association School of Architecture in London, England in 1954.
Ma, Frederick S. H. Hong Kong Special Administrative Region	Member of the Audit Committee and the Health, Safety and Environment Committee	Professor Ma has held senior management positions in international financial institutions and Hong Kong publicly listed companies in his career. He was also a former Principal Official with the Hong Kong Special Administrative Region Government.
	Director since July 2010	In addition to being a Director of Husky, he is currently the Non-Executive Chairman of MTR Corporation Limited (formerly Mass Transit Railway Corporation). In July 2002, Professor Ma joined the Government of the Hong Kong Special Administrative Region as the Secretary for Financial Services and the Treasury. He assumed the post of Secretary for Commerce and Economic Development in July 2007, but resigned from the Government in July 2008 due to medical reasons. Professor Ma was appointed as a member of the International Advisory Council of China Investment Corporation in July 2009. In January 2013, he was appointed a member of the Global Advisory Council of the Bank of America. Professor Ma was appointed as an Honorary Professor of the School of Economics and Finance at the University of Hong Kong in October 2008. In August 2013, he was appointed as an Honorary Professor of the Faculty of Business Administration at the Chinese University of Hong Kong. Professor Ma obtained a Bachelor of Arts (Honours) degree in Economics and History from the University of Hong Kong in 1973, an Honorary Doctor of Social Sciences in October 2014 from Lingnan University and an Honorary Doctor of Social Sciences in October 2016 from City University of Hong Kong.

Magnus, George C. Hong Kong Special Administrative Region	Member of the Audit Committee Director since July 2010	Mr. Magnus is a Non-Executive Director of CK Hutchison Holdings Limited and CK Infrastructure Holdings Limited and an independent Non-Executive Director of HK Electric Investments Manager Limited. Mr. Magnus acted as an Executive Director of Cheung Kong (Holdings) Limited from 1980 and as Deputy Chairman from 1985 until his retirement from these positions in October 2005. He served as Deputy Chairman of Hutchison Whampoa Limited from 1985 to 1993 and as Executive Director from 1993 to 2005. He also served as Chairman of Hongkong Electric Holdings Limited (now known as Power Assets Holdings Limited) from 1993 to 2005. He was a Non-Executive Director of Power Assets Holding Limited from 2005 to 2012 and then an independent Non-Executive Director until January 2014. Mr. Magnus obtained a Bachelor of Arts degree in 1959. He obtained a Master's degree in Economics from King's College, Cambridge University in 1963.
McGee, Neil D. Luxembourg	Member of the Health, Safety and Environment Committee Director since November 2012	Mr. McGee is the Managing Director of Hutchison Whampoa Europe Investments S.à r.l. He is an Executive Director of Power Assets Holdings Limited. Prior to his joining Hutchison Whampoa Europe Investments S.à r.l., he served as Group Finance Director of Power Assets Holdings Limited from 2006 to 2012, Chief Financial Officer of Husky Oil Limited from 1998 to 2000 and Chief Financial Officer of Husky Energy Inc. from 2000 to 2005. Prior to joining Husky Oil Limited in 1998, Mr. McGee held various financial, legal and corporate secretarial positions with the CK Hutchison Holdings Group. Mr. McGee holds a Bachelor of Arts degree and a Bachelor of Laws degree from the Australian National University.
Peabody, Robert J. Alberta, Canada	President & Chief Executive Officer Director since December 2016	Mr. Peabody became a member of the Board of Directors and President and Chief Executive Officer of Husky on December 5, 2016. Mr. Peabody was appointed Chief Operating Officer in 2006 and was responsible for leading Husky's Upstream and Downstream segments, including Western Canada Conventional and Unconventional, Heavy Oil, Oil Sands, Atlantic Region and Exploration, as well as Refining and Upgrading operations. He was also responsible for the Safety, Engineering, Project Management and Procurement functions. Prior to joining Husky, he led four major businesses for BP plc in Europe and the United States. Mr. Peabody holds a Bachelor of Science degree in Mechanical Engineering from the University of British Columbia and a Master of Science degree in Management (Sloan Fellow) from Stanford University. Mr. Peabody is a member of the Association of Professional Engineers and Geoscientists of Alberta (APEGA) and Vice-Chairman of the Foothills Hospital Development Council.
Russel, Colin S. Gloucestershire, United Kingdom	Member of the Audit Committee and the Health, Safety and Environment Committee Director since February 2008	Mr. Russel is the founder and a director of Emerging Markets Advisory Services Ltd. (a business advisory company). Mr. Russel is a Director of CK Infrastructure Holdings Limited, CK Life Sciences Int'l., (Holdings) Inc. and ARA Asset Management Pte. Ltd. Mr. Russel was the Canadian Ambassador to Venezuela; Consul General for Canada in Hong Kong; Director for China of the Department of Foreign Affairs, Ottawa; Director for East Asian Trade in Ottawa; Senior Trade Commissioner for Canada in Hong Kong; Director for Japan Trade in Ottawa and was in the Trade Commissioner Service for Canada in Spain, Hong Kong, Morocco, the Philippines, London and India. Previously Mr. Russel was an international project manager with RCA Ltd., Canada and development engineer with AEI Ltd., UK. Mr. Russel received a degree in Electrical Engineering in 1962 and a Master's degree in Business Administration in 1971, both from McGill University, Canada.

Shaw, Wayne E. Ontario, Canada	Member of the Audit Committee and the Corporate Governance Committee Director since August 2000	Mr. Shaw is the President of G.E. Shaw Investments Limited. Prior to his retirement in April 2013, he was a Senior Partner with Stikeman Elliott LLP,Barristers and Solicitors. Mr. Shaw is also a Director of the Li Ka Shing (Canada) Foundation. 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 Upper Canada.
Shurniak, William Saskatchewan, Canada	Deputy Chair of the Board and Chair of the Audit Committee Director since August 2000	Mr. Shurniak was an independent Non-Executive Director of Hutchison Whampoa Limited until June 2015, when he became an independent Non-Executive Director of CK Hutchison Holdings Limited. From May 2005 to June 2011 he was a Director and Chairman of Northern Gas Networks Limited (a private distributor of natural gas in Northern England). Mr. Shurniak also held the following positions until his return to Canada in 2005: Director and Chairman of ETSA Utilities (a utility company) since 2000, Powercor Australia Limited (a utility company) since 2000, CitiPower Pty Ltd. (a utility company) since 2002, and a Director of Envestra Limited (a natural gas distributor) since 2000, CrossCity Motorways Pty Ltd. (an infrastructure and transportation company) since 2002 and Lane Cove Tunnel Company Pty Ltd. (an infrastructure and transportation company) since 2004. Mr. Shurniak obtained an Honorary Doctor of Laws degree from the University of Saskatchewan in May 1998 and from The University of Western Ontario in October 2000. On July 30, 2005, he was a recipient of the Saskatchewan Centennial Medal from the Lieutenant Governor of Saskatchewan. In 2009 he was awarded the Saskatchewan Order of Merit by the Government of the Province of Saskatchewan. In December 2012, Mr. Shurniak was a recipient of The Queen Elizabeth II Diamond Jubilee Medal from the Lieutenant Governor of Saskatchewan. On June 4, 2014, the University of Regina conferred an Honorary Doctor of Laws degree on Mr. Shurniak and on November 10, 2016 he was awarded the Meritorious Service Medal by the Governor General of Canada.
Sixt, Frank J. Hong Kong Special Administrative Region	Member of the Compensation Committee Director since August 2000	Mr. Sixt is an Executive Director, Group Finance Director and Deputy Managing Director of CK Hutchison Holdings Limited. Mr. Sixt is also the Non-Executive Chairman of TOM Group Limited, an Executive Director of CK Infrastructure Holdings 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.

Officers

The following are the names and residences of the officers 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.

Name and Residence	Office or Position	Principal Occupation During Past Five Years
Peabody, Robert J. Alberta, Canada	President & Chief Executive Officer	President & Chief Executive Officer of Husky since December 2016. Chief Operating Officer of Husky from April 2006 to December 2016.
Hart, Jeffrey R. Alberta, Canada	Chief Financial Officer	Chief Financial Officer of Husky since November 2018. Acting Chief Financial Officer of Husky from April 2018 to November 2018. Vice President, Controller of Husky from October 2015 to April 2018.
Symonds, Robert W. P. Alberta, Canada	Chief Operating Officer	Chief Operating Officer of Husky since March 2017. Senior Vice President, Western Canada Production of Husky Oil Operations Limited from April 2012 to March 2017.
Girgulis, James D. Alberta, Canada	Senior Vice President, General Counsel & Secretary	Senior Vice President, General Counsel & Secretary since April 2012. Vice President, Legal & Corporate Secretary of Husky from August 2000 to April 2012.

As at February 15, 2019, the directors and officers of Husky, as a group, beneficially owned or controlled or directed, directly or indirectly, 814,498 common shares of Husky, representing less than one percent of the issued and outstanding common shares.

Conflicts of Interest

The 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 *Business Corporations Act* (Alberta), 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 have been within the past ten 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 ten 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, other than as follows. Mr. Glynn was director of MF Global Holdings Ltd. when it filed for Chapter 11 bankruptcy in the U.S. on October 31, 2011. Mr. Glynn is no longer a director of MF Global Holdings Ltd.

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) have, within the past ten 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) have 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.

AUDIT COMMITTEE

Composition

The members of Husky's Audit Committee (the "Committee") are William Shurniak (Chair), Stephen E. Bradley, Frederick S. H. Ma, George C. Magnus, Colin S. Russel and Wayne E. Shaw. Each of the members of the Committee is independent in that each member does not have a direct or indirect material relationship with the Company. Multilateral Instrument 52-110 *Audit Committees* provides that a material relationship is a relationship which could, in the view of the Company's Board of Directors, reasonably interfere with the exercise of a member's independent judgment.

The Committee's Mandate provides that the Committee is to be comprised of at least three members of the Board, all of whom shall be independent and meet the financial literacy requirements of applicable laws and regulations. Each member of the Committee is financially literate in that each has the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of the issues that can reasonably be expected to be raised by the Company's financial statements.

The education and experience of each Committee member that is relevant to the performance of his responsibilities as a Committee member is as follows.

William Shurniak (Chair) - Mr. Shurniak was an independent Non-Executive Director of Hutchison Whampoa Limited until June 2015, when he became an independent Non-Executive Director of CK Hutchison Holdings Limited, a newly listed company on The Stock Exchange of Hong Kong Limited. From May 2005 to June 2011 he was a Director and Chairman of Northern Gas Networks Limited (a private distributor of natural gas in Northern England).

Stephen E. Bradley - Mr. Bradley is a Director of Broadlea Group Ltd., Senior Consultant, ICAP (Asia Pacific) and a Director of Swire Properties Ltd. (Hong Kong).

Frederick S. H. Ma - Professor Ma has served in senior positions in the private sector and has held Principal Official positions (minister equivalent) with the Hong Kong Special Administrative Region Government. Professor Ma is currently a member of the International Advisory Council of China Investment Corporation, China's Sovereign Fund, as well as an Honorary Professor of the University of Hong Kong.

George C. Magnus - Mr. Magnus is a Non-Executive Director of CK Hutchison Holdings Limited and Cheung Kong Infrastructure Holdings Limited and an independent Non-Executive Director of HK Electric Investments Manager Limited and HK Electric Investments Limited.

Colin S. Russel - Mr. Russel is the founder and Managing Director of Emerging Markets Advisory Services Ltd. Mr. Russel is a director and an audit committee member of Cheung Kong Infrastructure Holdings Limited, CK Life Sciences Int'l., (Holdings) Inc. and ARA Asset Management Pte. Ltd.

Wayne E. Shaw - Mr. Shaw is the President of G.E. Shaw Investments ULC. Prior to his retirement in April 2013, he was a Senior Partner with Stikeman Elliott LLP, Barristers and Solicitors. Mr. Shaw is also a Director of the Li Ka Shing (Canada) Foundation.

Husky's Audit Committee Mandate is attached hereto as Appendix A.

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 auditor, during the fiscal years indicated:

($ thousands)	**2018**	2017
Audit Fees	**3,612**	3,861
Audit-related Fees	**249**	256
Tax Fees	**226**	121
	4,087	4,238

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 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 Committee pre-approved all of the audit-related and tax services provided by KPMG LLP in 2018.

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 percent 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.

TRANSFER AGENTS AND REGISTRARS

Husky's transfer agent and registrar is Computershare Trust Company of Canada. In the United States, the transfer agent and registrar is Computershare Trust Company, Inc. The registers for transfers of the Company's common and preferred shares are maintained by Computershare Trust Company of Canada at its principal offices in the cities of Calgary, Alberta and Toronto, Ontario. Queries should be directed to Computershare Trust Company at 1-800-564-6253 or 1-514-982-7555.

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, 2018 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 one percent 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 information, including directors' and officers' remuneration, principal shareholders of Husky's common shares and a description of options to purchase common shares is contained in Husky's Management Information Circular prepared in connection with the annual meeting of shareholders held on April 26, 2018.

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, 2018.

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 general strategic plans and growth strategies; 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, 2018; the Company's 2019 production estimates broken down by product type and location; and anticipated effects of and cost of compliance with certain future or proposed laws and regulations on the Company's operations;

- with respect to the Company's thermal developments: estimated production and expected timing of first production from the Dee Valley, Spruce Lake Central, Spruce Lake North, Spruce Lake East, Edam Central, Dee Valley 2 and Westhazel projects; the expected timing of regulatory approvals for the Dee Valley 2 and Westhazel projects; and the expected impact of the Alberta government-mandated production curtailment on the Tucker Thermal Project and the Sunrise Energy Project;

- with respect to the Company's non-thermal developments, the expected impact of the Alberta government-mandated production curtailment;

- with respect to the Company's Western Canada resource plays, strategic and drilling plans;

- with respect to the Company's Offshore business in Asia Pacific: the expected timing of commencement of drilling of the remaining three wells at, and first gas production from, Liuhua 29-1; target production from Liuhua 29-1 when fully ramped up; timing for a second exploration well on Block 16/25; the expected timing of drilling five MDA field production wells and two MBH field production wells, and the expected timing of first gas production and sales therefrom; and the expected timing of development and tie-in of the additional MDK shallow water field;

- with respect to the Company's Offshore business in Atlantic: development plans, expected timing of first oil and expected volume and timing of peak production at the West White Rose Project; and delineation plans at the A-24 exploration well;

- with respect to the Company's Infrastructure and Marketing business: the processing capacity expected to be added by the Ansell Corser Gas Plant when it comes online, and the expected timing thereof; and

- with respect to the Company's Downstream operating segment: the expected timing that operations at the Superior Refinery will resume; plans to increase asphalt modification capacity, expand asphalt sales in U.S. markets and further market residual production; plans to market and potentially sell the Prince George Refinery and the Retail and Commercial Network; and the expected timing of completion of the crude oil flexibility project at the Lima Refinery.

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, 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, thermal and non-thermal developments in the Integrated Corridor, Western Canada resource plays and Infrastructure and Marketing business: 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, 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 the Company's Downstream operating segment: 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, 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, 2018; the demand for the Company's products and prices received for crude oil and 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 the Block 29/26 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, thermal and non-thermal developments in the Integrated Corridor, Western Canada resource plays and Infrastructure and Marketing business: 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 the Company's Downstream operating segment: the costs to operate properties, plants and equipment in an efficient, reliable and safe manner; regulatory (environmental, license 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, 2018, 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 the term "operating netback", which is a common non-GAAP metric used in the oil and gas industry and is not used to enhance the Company's reported financial performance or position. Management believes 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 gross revenue less royalties, production and operating and transportation costs on a per unit basis.

This AIF contains the term "funds from operations", which is a non-GAAP measure that does not have a standardized meaning prescribed by IFRS and therefore is unlikely to be comparable to similar measures presented by other issues. It is common in the reports of other companies but may differ by definition and application. Funds from operations should not be considered an alternative to, or more meaningful than, "cash flow - operating activities" as determined in accordance with IFRS, as an indicator of financial performance. Funds from operations equals cash flow - operating activities plus change in non-cash working capital. Management believes that impacts of noncash working capital items on cash flow - operating activities may reduce comparability between periods, accordingly, funds from operations is presented in the Company's financial reports to assist management and investors in analyzing operating performance of the Company in the stated period compared to prior periods.

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, 2018 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, 2018.

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 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 incremental proved reserve additions for that period divided by the Company's Upstream gross production for the same period. The reserves replacement ratio measures the amount of reserves added 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 percent for the company to maintain its reserves. The reserves replacement ratio only measures the amount of reserves added to a company's reserve base during a given period. 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.

This document includes estimates of net pay thickness at White Rose A-24 and A-78, which estimates may be considered to be anticipated results under NI 51-101. The estimates were prepared internally. The risks and uncertainties associated with recovery of resources from A-24 and A-78 include, but are not limited to: that Husky may encounter unexpected drilling results; the occurrence of unexpected events in the exploration for, and the operation and development of, oil and gas; delays in anticipated timing of drilling and completion of wells; geological, technical, drilling and processing problems; and other difficulties in producing petroleum reserves.

Note to U.S. Readers

The Company reports its reserves and resources information in accordance with Canadian practices and specifically in accordance with National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities*, 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.

Appendix A

Husky Energy Inc.

Audit Committee Mandate

Purpose

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

1. the quarterly and annual financial statements and quarterly and annual MD&A, which are to be provided to shareholders and the appropriate regulatory agencies;
2. earnings press releases before the Corporation publicly discloses this information;
3. the system of internal controls that management has established;
4. the internal and external audit process;
5. the appointment of external auditors;
6. the appointment of qualified reserves evaluators or auditors;
7. the filing of statements and reports with respect to the Corporation's oil and gas reserves; and
8. the identification, management and mitigation of major financial risk exposures of the Corporation.

In addition, the Committee provides an avenue for communication between the Board and each of the Chief Financial Officer of the Corporation and other senior financial management, internal audit, the external auditors, external qualified reserves evaluators or auditors and internal qualified reserves evaluators. It is expected that the Committee will have a clear understanding with the external auditors and the external reserve evaluators or auditors that an open and transparent relationship must be maintained with the Committee.

While the Committee has the responsibilities and powers set forth in this Mandate, the role of the Committee is oversight. The members of the Committee are not full time employees of the Corporation and may or may not be accountants or auditors by profession or experts in the fields of accounting, or auditing and, in any event, do not serve in such capacity. Consequently, it is not the duty of the Committee to plan or conduct financial audits or reserve audits or evaluations, or to determine that the Corporation's financial statements are complete, accurate and are in accordance with applicable accounting or reserve principles. This is the responsibility of management and the external auditors and, as to reserves, the external reserve evaluators or auditors. Management and the external auditors will also have the responsibility to conduct investigations and to assure compliance with laws and regulations and the Corporation's business conduct guidelines.

Composition

The Committee will consist of not less than three directors, all of whom will be independent and will satisfy the financial literacy requirements of securities regulatory requirements.

One of the members of the Committee will be an audit committee financial expert as defined in applicable securities regulatory requirements.

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 of the Board 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 of the Board.

Meetings

The Committee will meet at least four times annually on dates determined by the Chair or 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 Corporation. The secretary will keep minutes of the meetings of the Committee. Minutes will be sent to all Committee members, on a timely basis.

As necessary or desirable, but in any case at least quarterly, the Committee shall meet with members of management and representatives of the external auditors and internal audit in separate executive sessions to discuss any matters that the Committee or any of these groups believes should be discussed privately.

As necessary or desirable, but in any case at least annually, the Committee will meet the management and representatives of the external reserves evaluators or auditors and internal reserves evaluators in separate executive sessions to discuss matters that the Committee or any of these groups believes should be discussed privately.

Authority

Subject to any prior specific directive by the Board, the Committee is granted the authority to investigate any matter or activity involving financial accounting and financial reporting, the internal controls of the Corporation and the reporting of the Corporation's reserves and oil and gas activities.

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

In recognition of the fact that the external auditors are ultimately accountable to the Committee, the Committee will have the authority and responsibility to recommend to the Board the external auditors that will be proposed for nomination at the annual general meeting. The external auditors will report directly to the Committee, and the Committee will evaluate and, where appropriate, replace the external auditors. The Committee will approve the fees and terms for all audit engagements and all non-audit engagements with the external auditors. The Committee will consult with management and the internal audit group regarding the engagement of the external auditors but will not delegate these responsibilities.

The external qualified reserves evaluators or auditors will report directly to the Committee, and the Committee will evaluate and, where appropriate, replace the external qualified reserves evaluators or auditors. The Committee will approve the fees and terms for all reserves evaluators or audit engagements. The Committee will consult with management and the internal qualified reserves evaluator's group regarding the engagement of the external qualified reserves evaluators or auditors but will not delegate these responsibilities.

Specific Duties & Responsibilities

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

Audit

1. Review and reassess the adequacy of this Mandate annually and recommend any proposed changes to the Corporate Governance Committee and the Board for approval.
2. Review with the Corporation's management, internal audit and the external auditors and recommend to the Board for approval the Corporation's annual financial statements and annual MD&A which is to be provided to shareholders and the appropriate regulatory agencies and any financial statement contained in a prospectus, information circular, registration statement or other similar document.
3. Review with the Corporation's management, internal audit and the external auditors and approve the Corporation's quarterly financial statements and quarterly MD&A which is to be provided to shareholders and the appropriate regulatory agencies.
4. Review with the Corporation's management and approve earnings press releases before the Corporation publicly discloses this information.
5. Be responsible for the oversight of the work of the external auditors, including the resolution of disagreements between management of the Corporation and the external auditors regarding financial reporting.

6. Review with the Corporation's management, internal audit and the external auditors the Corporation's accounting and financial reporting controls and obtain annually, in writing from the external auditors their observations, if any, on material weaknesses in internal controls over financial reporting as noted during the course of their work.
7. Review with the Corporation's management, internal audit and the external auditors significant accounting and reporting principles, practices and procedures applied by the Corporation in preparing its financial statements, and discuss with the external auditors their judgments about the quality (not just the acceptability) of the Corporation's accounting principles used in financial reporting.
8. Review the scope of internal audit's work plan for the year and receive a summary report of major findings by internal audit and how management is addressing the conditions reported.
9. Review the scope and general extent of the external auditors' annual audit, such review to include an explanation from the external auditors of the factors considered in determining the audit scope, including the major risk factors, and the external auditor's confirmation whether or not any limitations have been placed on the scope or nature of their audit procedures.
10. Inquire as to the independence of the external auditors and obtain from the external auditors, at least annually, a formal written statement delineating all relationships between the external auditors and the Corporation as contemplated by Independence Standards Board Standard No. 1, Independence Discussions with Audit Committees.
11. Arrange with the external auditors that (a) they will advise the Committee, through its Chair and management of the Corporation, of any matters identified through procedures followed for the review of interim quarterly financial statements of the Corporation, such notification is to be made prior to the related press release and (b), for written confirmation at the end of each of the first three quarters of the year, that they have nothing to report to the Committee, if that is the case, or the written enumeration of required reporting issues.
12. Review at the completion of the annual audit, with senior management, internal audit and the external auditors the following:
    i. the annual financial statements and related footnotes and financial information to be included in the Corporation's annual report to shareholders;
    ii. results of the audit of the financial statements and the related report thereon and, if applicable, a report on changes during the year in accounting principles and their application;
    iii. significant changes to the audit plan, if any, and any serious disputes or difficulties with management encountered during the audit;
    iv. inquire about the cooperation received by the external auditors during their audit, including access to all requested records, data and information; and
    v. inquire of the external auditors whether there have been any material disagreements with management, which, if not satisfactorily resolved, would have caused them to issue a non-standard report on the Corporation's financial statements.
13. Discuss (a) with the external auditors, without management being present, (i) the quality of the Corporation's financial and accounting personnel, and (ii) the completeness and accuracy of the Corporation's financial statements, and (b) elicit the comments of senior management regarding the responsiveness of the external auditors to the Corporation's needs.
14. Meet with management to discuss any relevant significant recommendations that the external auditors may have, particularly those characterized as 'material' or 'serious' (typically, such recommendations will be presented by the external auditors in the form of a Letter of Comments and Recommendations to the Committee) and review the responses of management to the Letter of Comments and Recommendations and receive follow-up reports on action taken concerning the aforementioned recommendations.
15. Review and approve disclosures required to be included in periodic reports filed with Canadian and U.S. securities regulators with respect to non-audit services performed by the external auditors.
16. Establish adequate procedures for the review of the Corporation's disclosure of financial information extracted or derived from the Corporation's financial statements, and periodically assess the adequacy of those procedures.
17. Establish procedures for (a) the receipt, retention and treatment of complaints received by the Corporation regarding accounting, internal accounting controls or auditing matters, and (b) the confidential, anonymous submission by employees of the Corporation of concerns regarding questionable accounting or auditing matters.
18. Review and approve the Corporation's hiring policies regarding partners, employees and former partners and employees of the present and former external auditors.
19. Review the appointment and replacement of the senior internal audit executive.
20. Review with management, internal audit and the external auditors the methods used to establish and monitor the Corporation's policies with respect to unethical or illegal activities by the Corporation's employees that may have a material impact on the financial statements or other reporting of the Corporation.
21. Reviewing generally, as part of the review of the annual financial statements, a report, from the Corporation's general counsel concerning legal, regulatory and compliance matters that may have a material impact on the financial statements or other reporting of the Corporation.
22. Review and discuss with management, on a regular basis, the identification, management and mitigation of major financial risk exposures across the Corporation. In addition, the Committee oversees the Corporation's risk management framework and related processes.

Reserves

23. Review, with reasonable frequency, the Corporation's procedures relating to the disclosure of information with respect to the Corporation's oil and gas reserves, including the Corporation's procedures for complying with the disclosure requirements and restrictions of applicable regulatory requirements.
24. Review with management the appointment of the external qualified reserves evaluators or auditors, and in the case of any proposed change in such appointment, determine the reasons for the change and whether there have been disputes between management and the appointed external qualified reserves evaluators or auditors.
25. Review, with reasonable frequency, the Corporation's procedures for providing information to the external qualified reserves evaluators or auditors who report on reserves and data for the purposes of compliance with applicable securities regulatory requirements.
26. Meet, before the approval and release of the Corporation's reserves data and the report of the qualified reserve evaluators or auditors thereon, with senior management, the external qualified reserves evaluators or auditors and the internal qualified reserves evaluators to determine whether any restrictions affect their ability to report on reserves data without reservation and to review the reserves data and the report of the qualified reserves evaluators or auditors.
27. Recommend to the Board for approval of the content and filing of required statements and reports relating to the Corporation's disclosure of reserves data as prescribed by applicable regulatory requirements.

Miscellaneous

28. Review and approve (a) any change or waiver in the Corporation's Code of Business Conduct for the President and Chief Executive Officer and senior financial officers and (b) any public disclosure made regarding such change or waiver and, if satisfied, refer the matter to the Board for approval.
29. Act in an advisory capacity to the Board.
30. Carry out such other responsibilities as the Board may, from time to time, set forth.
31. 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 details as is reasonably appropriate.

Effective Date: May 6, 2014

Husky Energy Inc.

Report on Reserves Data by Independent Qualified Reserves Auditor

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, 2018. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2018, 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 percent, included in the reserves data of the Company audited and reviewed for the year ended December 31, 2018, 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$)	Total (MM$)
Sproule Associates Limited	December 31, 2018	Canada	16,839.4	Nil	687.1	17,526.5
		China	4,438.2	Nil	—	4,438.2
		Indonesia	846.5	Nil	—	846.5
			22,124.1	**Nil**	**687.1**	**22,811.2**

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 31, 2019

/s/ Art McMullen, P.Eng.
Art McMullen, P.Eng.
Senior Manager, Engineering and Regional Director, Asia Pacific

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

/s/ Jeff Jackson, P.Eng.
Jeff Jackson, P.Eng.
Petroleum Engineer

/s/ Cameron P. Six, P.Eng.
Cameron P. Six, P.Eng.
President and Chief Executive Officer

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/ Robert J. Peabody — February 25, 2019

Robert J. Peabody
President & Chief Executive Officer

/s/ Robert W. P. Symonds — February 25, 2019

Robert W. P. Symonds
Chief Operating Officer

/s/ William Shurniak — February 25, 2019

William Shurniak
Director

/s/ Stephen E. Bradley — February 25, 2019

Stephen E. Bradley
Director

Husky Energy Inc.

Independent Qualified Reserves Auditor Audit Opinion

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

Attention: Mr. Richard Leslie, Manager Reserves

Re: Audit of Husky Energy Inc.'s 2018 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, 2018. 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 2018 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 2018 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, 2018		
	Working Interest Before Royalty Company Share of Remaining Reserves (mmboe)	Company Share of Net Present Value Before Income Tax (MM$) @ 10%
Total Proved	1,471	13,018
Total Proved Plus Probable	2,541	22,811

Sincerely,

Sproule Associates Limited

/s/ Cameron P. Six, P. Eng.
Cameron P. Six, P. Eng.
President and Chief Executive Officer
Calgary, Alberta
January 31, 2019