PEYTO

Exploration & Development Corp.

ANNUAL INFORMATION FORM

2018

March 28, 2019

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GLOSSARY OF TERMS

"**2008 Arrangement**" means the arrangement under the provisions of section 193 of the ABCA among the Trust, its subsidiaries and Unitholders which was completed on January 1, 2008 pursuant to which the Internal Reorganization was completed;

"**2010 Arrangement**" means the arrangement under the provisions of section 193 of the ABCA among the Trust, POT, Peyto AdminCo, the Peyto Partnership, PEDC, Peyto Exploration (2011) Ltd. and Unitholders which commenced on December 31, 2010 and was completed on January 1, 2011 and resulted in the reorganization of the Trust into a public, dividend paying, oil and natural gas exploration and development company that acquired all of the assets and assumed all of the liabilities of the Trust;

"**2012 Amalgamation**" means the amalgamation of Peyto and Open Range, its wholly-owned subsidiary, effective December 31, 2012 pursuant to subsection 184(1) of the ABCA;

"**2012 Arrangement**" means the arrangement under the provisions of section 193 of the ABCA among Peyto, Open Range and the shareholders of Open Range which was completed on August 14, 2012 and resulted in Peyto acquiring all of the issued and outstanding common shares of Open Range;

"**2015 Senior Notes**" means the $100 million senior unsecured notes issued on May 1, 2015, which bear a coupon rate of 4.26%, which interest is payable semi-annually in arrears, and mature in May 2025;

"**ABCA**" means the *Business Corporations Act* (Alberta), R.S.A. 2000, c. B-9, as amended, including the regulations promulgated thereunder;

"**Common Shares**" means the common shares in the capital of Peyto;

"**Direct Royalties**" means royalty interests in petroleum and natural gas rights acquired by Peyto from time to time;

"**InSite**" means InSite Petroleum Consultants Ltd., independent oil and gas reservoir engineers of Calgary, Alberta;

"**InSite Report**" means the independent engineering evaluation of Peyto's oil, NGLs and natural gas interests prepared by InSite dated February 14, 2019 and effective December 31, 2018, a summary of which is contained herein;

"**Internal Reorganization**" means the reorganization of the Trust's subsidiaries effective January 1, 2008, whereby all of the oil and natural gas assets and liabilities of the PEDC entities were transferred to the Peyto Partnership;

"**oil and natural gas properties**" means the working, royalty or other interests of Peyto from time to time in any petroleum and natural gas rights, tangibles and miscellaneous interests, including the properties in which Peyto has an interest as at the date hereof, and properties which may be acquired by Peyto at a future date, and including the Direct Royalties;

"**Open Range**" means Open Range Energy Corp., a corporation incorporated under the ABCA;

"**PEDC**" means Peyto Exploration & Development Corp., a corporation amalgamated under the ABCA and a predecessor to Peyto;

"**Peyto**", the "**Corporation**", "**we**", "**us**" or "**our**" means, as the context requires, (i) Peyto Exploration & Development Corp., a corporation amalgamated under the ABCA on December 31, 2012 pursuant to the 2012 Amalgamation; (ii) Peyto Exploration & Development Corp., a corporation amalgamated under the ABCA on January 1, 2011 pursuant to the 2010 Arrangement; or (iii) the Trust, and its controlled entities on a consolidated basis, prior to the completion of the 2010 Arrangement;

"**Peyto AdminCo**" means Peyto Energy Administration Corp., a corporation incorporated under the ABCA;

"**Peyto Partnership**" means Peyto Energy Limited Partnership, a limited partnership formed pursuant to the laws of the Province of Alberta;

"**POT**" means Peyto Operating Trust, a trust established under the laws of Alberta pursuant to the amended and restated trust indenture dated January 1, 2008 between Valiant Trust Company, the Trust and Peyto AdminCo;

"**Shareholders**" means holders of Common Shares;

"**Trust**" means Peyto Energy Trust, a trust established under the laws of Alberta and predecessor to Peyto. All references to the "Trust", unless the context otherwise requires, are references to Peyto Energy Trust and its controlled entities on a consolidated basis prior to completion of the 2010 Arrangement;

"**Trust Units**" means previously outstanding trust units of the Trust, each unit representing an equal undivided beneficial interest therein;

"**TSX**" means the Toronto Stock Exchange;

"**United States**" or "**U.S.**" means the United States of America; and

"**Unitholders**" means the former holders of the Trust Units.

Unless otherwise specified, information in this Annual Information Form is as at the end of the Corporation's most recently completed financial year, being December 31, 2018.

Words importing the singular number only include the plural, and vice versa, and words importing any gender include all genders.

All dollar amounts set forth in this Annual Information Form are in Canadian dollars, except where otherwise indicated.

ABBREVIATIONS

Oil and Natural Gas Liquids	
bbl	barrels
Mbbl	thousand barrels
MMbbl	million barrels
NGLs	natural gas liquids
Mboe	thousand barrels of oil equivalent
MMboe	million barrels of oil equivalent
boe/d	barrels of oil equivalent per day
bbls/d	barrels of oil per day

Natural Gas	
Mcf	thousand cubic feet
MMcf	million cubic feet
Mcf/d	thousand cubic feet per day
MMcf/d	million cubic feet per day
m^3	cubic metres
MMbtu	million British Thermal Units
GJ	Gigajoule

Other

BOE or boe — means barrel of oil equivalent, using the conversion factor of 6 Mcf of natural gas being equivalent to one bbl of oil. **BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6 Mcf:1 bbl, utilizing a conversion on a 6 Mcf:1 bbl basis may be misleading as an indication of value.**

McfGE — means thousand cubic feet of natural gas equivalent, using the conversion factor of one bbl of oil to 6 Mcf of natural gas. **McfGEs may be misleading, particularly if used in isolation. An McfGE conversion ratio of 1 bbl:6 Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 1 bbl: 6 Mcf, utilizing a conversion on a 1 bbl: 6 Mcf basis may be misleading as an indication of value.**

WTI — means West Texas Intermediate.

°API — means the measure of the density or gravity of liquid petroleum products derived from a specific gravity.

M$ — means thousands of dollars.

MM$ — means millions of dollars.

km — means kilometres.

CONVERSION

The following table sets forth certain conversions between Standard Imperial Units and the International System of Units (or metric units).

To Convert From	To	Multiply By
Mcf	cubic metres	28.174
cubic metres	cubic feet	35.494
bbls	cubic metres	0.159
cubic metres	bbls	6.289
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.405
hectares	acres	2.471
GJ	MMbtu	0.950

NOTICE TO READER

YOU SHOULD NOT RELY ON FORWARD-LOOKING STATEMENTS BECAUSE THEY ARE INHERENTLY UNCERTAIN.

Certain statements contained in this Annual Information Form constitute forward-looking statements or forward-looking information (collectively, "**forward-looking statements**") within the meaning of applicable Canadian securities laws. These forward-looking statements relate to future events or Peyto's future performance. All statements other than statements of historical fact are forward-looking statements. The use of any of the words "anticipate", "plan", "continue", "estimate", "expect", "may", "will", "project", "predict", "potential", "should", "believe" and similar expressions are intended to identify forward-looking statements. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. These statements speak only as of the date of this Annual Information Form.

Forward-looking statements are based on a number of factors and assumptions which have been used to develop such forward-looking statements but which may prove to be incorrect. Although Peyto believes that the expectations reflected in such forward-looking statements are reasonable, undue reliance should not be placed on forward-looking statements because Peyto can give no assurance that such expectations will prove to be correct. In addition to other factors and assumptions which may be identified in this Annual Information Form, assumptions have been made regarding, among other things: the impact of increasing competition; the general stability of the economic and political environment in which Peyto operates; the timely receipt of any required regulatory approvals; the ability of Peyto to obtain qualified staff, equipment and services in a timely and cost efficient manner; drilling results; the ability of the operator of the projects which Peyto has an interest in to operate the field in a safe, efficient and effective manner; the ability of Peyto to obtain financing on acceptable terms; field production rates and decline rates; the ability to replace and expand oil and natural gas reserves through acquisitions, development and exploration; the timing and costs of pipeline, storage and facility construction and expansion and the ability of Peyto to secure adequate product transportation; future oil and natural gas prices; currency, exchange and interest rates; the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which Peyto operates; and the ability of Peyto to successfully market its oil and natural gas products.

In particular, this Annual Information Form contains forward-looking statements pertaining to the following:

- the performance characteristics of the oil and natural gas assets of Peyto;
- oil and natural gas production levels;
- market prices for oil and natural gas, including pricing assumptions used in the Reserves Data (as defined herein);
- the size of Peyto's oil and natural gas reserves;
- projections of market prices and costs and the related sensitivities of dividends;
- supply and demand for oil and natural gas;
- expectations regarding the ability to raise capital and to continually add to reserves through exploration and development and, if applicable, acquisitions;
- treatment under governmental regulatory regimes;
- capital expenditures programs;
- the payment of dividends;
- the existence, operation and strategy of Peyto's commodity price risk management program;
- the approximate and maximum amount of forward sales and hedging to be employed by Peyto;
- Peyto's future tax horizons;
- the impact of Canadian federal and provincial governmental regulation on Peyto; and
- the goal to grow or sustain production and reserves through prudent exploration, management and acquisitions.

The actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and elsewhere in this Annual Information Form:

- volatility in market prices for oil and natural gas;
- liabilities inherent in oil and natural gas operations;
- uncertainties associated with estimating oil and natural gas reserves;
- risks and uncertainties associated with Peyto's oil and natural gas exploration and development program;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- incorrect assessments of the value of acquisitions and exploration and development programs;

- geological, technical, drilling and processing problems;
- fluctuations in foreign exchange or interest rates and stock market volatility;
- restrictions and/or limitations on transportation, including pipeline systems;
- uncertainties associated with changes in legislation, including, but not limited to, changes in income tax laws and oil and natural gas royalty and regulatory frameworks; and
- the other factors discussed under "*Risk Factors*".

Statements relating to reserves are deemed to be forward-looking statements as they involve the implied assessment, based on current estimates and assumptions, that the reserves described can be profitably produced in the future. The foregoing lists of factors are not exhaustive. The forward-looking statements contained in this Annual Information Form are expressly qualified by this cautionary statement. Peyto does not undertake any obligation to publicly update or revise any forward-looking statements, except as required by applicable securities law.

PEYTO EXPLORATION & DEVELOPMENT CORP.

General

Peyto is a Calgary, Alberta based company founded in 1998. Peyto is a growth oriented, dividend paying publicly traded company engaged in the acquisition, exploration, development and production of oil and natural gas in Western Canada. The head and principal office of Peyto is located at Suite 300, 600 – 3rd Avenue S.W., Calgary, Alberta T2P 0G5. The registered office of Peyto is located at Suite 2400, 525 – 8th Avenue S.W., Calgary, Alberta T2P 1G1.

The Common Shares trade on the TSX under the symbol "PEY".

Corporate History

PEDC was founded in 1998 as an oil and natural gas exploration and development company.

The Trust was formed on May 22, 2003 and commenced operations on July 1, 2003 as a result of the completion of an arrangement under the provisions of section 193 of the ABCA among PEDC, Peyto Acquisition Corp. and the Trust which was completed on July 1, 2003 and pursuant to which former holders of common shares of PEDC received Trust Units and PEDC became an indirect subsidiary of the Trust.

On January 1, 2008, the Trust completed the 2008 Arrangement. As a result of the Internal Reorganization, all of the oil and natural gas assets of the Trust were held in the Peyto Partnership, Peyto AdminCo was the administrator of the Trust and POT and PEDC was the general partner of the Peyto Partnership prior to completion of the 2010 Arrangement. Certain subsidiaries of the Trust were amalgamated pursuant to the Internal Reorganization.

On January 1, 2011, the Corporation completed the 2010 Arrangement pursuant to which Peyto, directly or indirectly, acquired all of the assets and assumed all of the liabilities of the Trust. Prior to completion of the 2010 Arrangement, the Trust was a reporting issuer in all provinces of Canada and the Trust Units were listed for trading on the TSX. Following completion of the 2010 Arrangement, the Common Shares were listed for trading on the TSX concurrent with the delisting of the Trust Units, the Trust ceased to be a reporting issuer and Peyto became a reporting issuer as successor to the Trust in those jurisdictions in which the Trust was previously a reporting issuer. Pursuant to the terms of the 2010 Arrangement, Unitholders received one Common Share for each Trust Unit held.

On December 31, 2012, Peyto completed the 2012 Amalgamation pursuant to which Peyto amalgamated with Open Range, its wholly-owned subsidiary.

Inter-Corporate Relationships

Peyto does not have any subsidiaries.

GENERAL DEVELOPMENT OF THE BUSINESS

General

Peyto is a Calgary, Alberta based dividend paying energy company which has been engaged in the acquisition, exploration, development and production of oil and natural gas in Western Canada since it was founded in 1998. Peyto's strategy is to enhance Shareholder value through the exploration, discovery and low cost development of oil and natural gas in the Western Canadian sedimentary basin. Peyto's portfolio of assets includes exploration, exploitation and development opportunities located primarily in the Deep Basin of Alberta. Management's current model is designed to deliver a superior total return with growth in value, assets, production and income, all on a debt adjusted per share basis. The model is built around three key strategies:

- Use technical expertise to achieve the best return on capital employed through the development of internally generated drilling projects;
- Build an asset base which is made up of high quality natural gas reserves; and
- Over time, balance dividends to shareholders paid with earnings, and cash flow, and balance funding for the capital program with cash flow, equity and available bank lines.

Three Year History

The following is a summary of the development of Peyto's business for the periods shown.

2016

During 2016, Peyto drilled or participated in 128 gross (121 net) oil and natural gas wells. Of the 128 gross wells, 128 wells (121 net) reached total depth as at December 31, 2016. All but three wells were drilled horizontally using multi-stage fracturing technology. Capital expenditures for 2016 totalled $469.4 million. The average production for the year was 96,975 boe/d and the exit rate was 105,000 boe/d.

On May 18, 2016, Peyto completed a public offering of 5,390,625 Common Shares at a price of $32.00 per Common Share for gross proceeds of approximately $172.5 million.

On October 24, 2016, Peyto completed a private placement of an aggregate of $100 million senior unsecured notes (the "**2016 Senior Notes**"). The 2016 Senior Notes have a coupon rate of 3.7%, which interest is payable semi-annually in arrears, and mature on October 24, 2023. The 2016 Senior Notes were issued pursuant to an amended and restated note purchase and private shelf agreement dated April 26, 2013 between Peyto and a certain institutional investor and rank equally with Peyto's obligations under its bank facility and existing Senior Notes, including the 2015 Senior Notes.

In 2016, Peyto had earnings of $112.4 million and paid total dividends to Shareholders of $214.9 million.

2017

During 2017, Peyto drilled or participated in 142 gross (138 net) oil and natural gas wells. Of the 142 gross wells, 141 wells (137 net) reached total depth as at December 31, 2017. Seven of the 142 gross wells were drilled vertically with the remaining 135 wells drilled horizontally and completed using multi-stage fracturing technology. Capital expenditures for 2017 totalled $521.2 million. The average production for the year was 102,614 boe/d and the exit rate was 115,000 boe/d.

In 2017, Peyto had earnings of $176.6 million and paid total dividends to Shareholders of $217.6 million.

2018

During 2018, Peyto drilled or participated in 70 gross (67.25 net) oil and natural gas wells. Of the 70 gross wells, 70 wells (67.25 net) reached total depth as at December 31, 2018. All of the wells were drilled horizontally and completed using multi-stage fracturing technology. Capital expenditures for 2018 totalled $232.3 million. The average production for the year was 92,012 boe/d and the exit rate was 94,000 boe/d.

On January 2, 2018, Peyto completed a private placement of an aggregate of $100 million senior unsecured notes (the "**2018 Senior Notes**"). The 2018 Senior Notes have a coupon rate of 3.95%, which interest is payable semi-annually in arrears, and mature on January 2, 2028. The 2018 Senior Notes were issued pursuant to a note purchase agreement and a note purchase and private shelf agreement dated January 2, 2018 between Peyto and a certain institutional investor and rank equally with Peyto's obligations under its bank facility and existing Senior Notes, including the 2015 Senior Notes and the 2016 Senior Notes.

On January 11, 2018, Peyto announced that, starting with the January 2018 dividend, the Corporation's monthly dividend would be reduced from $0.11 per Common Share to $0.06 per Common Share.

Additionally on January 11, 2018, Peyto announced its intention to file a notice of intention with the TSX to make a normal course issuer bid to purchase up to 12,158,897 Common Shares (approximately 10% of the public float of the Common Shares at the time of announcement) through the facilities of the TSX. The normal course issuer bid commenced on January 22, 2018 and expired on January 21, 2019. No Common Shares were purchased under the normal course issuer bid.

On February 1, 2018, Mr. Jean-Paul Lachance was appointed Vice President, Engineering and Chief Operating Officer and Mr. Scott Robinson was appointed Executive Vice President, New Ventures.

In 2018, Peyto had earnings of $129.1 million and paid total dividends to Shareholders of $118.7 million.

Recent Developments

On January 3, 2019, Peyto completed a private placement of an aggregate of $100 million senior unsecured notes (the "**2019 Senior Notes**"). The 2019 Senior Notes have a coupon rate of 4.39%, which interest is payable semi-annually in arrears, and mature on January 3, 2026. The 2019 Senior Notes were issued pursuant to a note purchase agreement dated January 3, 2019 between Peyto and a certain institutional investor and rank equally with Peyto's obligations under its bank facility and existing Senior Notes, including the 2015 Senior Notes, the 2016 Senior Notes and the 2018 Senior Notes. Proceeds from the issuance of 2019 Senior Notes were used to repay the $100 million senior unsecured notes which matured on January 3, 2019.

On January 16, 2019, Peyto announced that, starting with the January 2019 dividend, the Corporation's monthly dividend would be temporarily reduced from $0.06 per Common Share to $0.02 per Common Share.

On January 25, 2019, Peyto announced that the TSX had accepted the Corporation's notice of intention to commence a normal course issuer bid to purchase up to 12,400,000 Common Shares (approximately 10% of the public float of the Common Shares at the time of announcement) through the facilities of the TSX. The normal course issuer bid commenced on January 30, 2019 and will expire on January 29, 2020. As at the date hereof, there were no Common Shares purchased and cancelled under the normal course issuer bid.

On February 1, 2019, Mr. Scott Robinson, Executive Vice President, New Ventures, retired from the Corporation.

DESCRIPTION OF THE BUSINESS AND OPERATIONS

Peyto is a growth oriented, dividend paying publicly traded company engaged in the acquisition, exploration, development and production of oil and natural gas in Western Canada.

Principal Properties

See "*Statement of Reserves Data and Other Oil and Gas Information – Other Oil and Gas Information – Oil and Gas Properties*".

Competitive Conditions

The oil and natural gas industry is competitive in all its phases. Peyto competes with numerous other entities in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas. Peyto's competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than those of Peyto. Peyto's ability to increase its reserves in the future will depend not only on its ability to explore and develop its present properties, but also on its ability to select and acquire other suitable producing properties or prospects for exploratory drilling. Competitive factors in the distribution and marketing of oil and natural gas include price and methods and reliability of delivery and storage. Competition may also be presented by alternate fuel sources. Peyto believes that it has a competitive advantage to that of other oil and natural gas issuers of similar size, involved in similar areas and at a similar stage of development as a result of Peyto's low cost development of its oil and natural gas properties.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The statement of reserves data and other oil and natural gas information set forth below (the "**Statement**") is dated February 14, 2019. The effective date of the Statement is December 31, 2018 and the preparation date of the Statement is March 13, 2019. The Report of Management and Directors on Reserves Data and Other Information on Form 51-101F3 and the Report on Reserves Data by InSite on Form 51-101F2 are attached as Schedules A and B, respectively, to this Annual Information Form.

Disclosure of Reserves Data

The Statement set forth below discloses the Corporation's reserves data (the "**Reserves Data**") is based upon an evaluation by InSite with an effective date of December 31, 2018 contained in the InSite Report. The Reserves Data summarizes the oil, liquids and natural gas reserves of Peyto and the net present values of future net revenue for these reserves using forecast prices and costs. The Reserves Data conforms to the requirements of National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities* ("**NI 51-101**") and is in accordance with the COGE Handbook. Additional information not required by NI 51-101 has been presented to provide continuity and additional information which we believe is important to the readers of this information. Peyto engaged InSite to provide an evaluation of proved and proved plus probable reserves and no attempt was made to evaluate possible reserves.

All of Peyto's reserves are in Canada, specifically, in the province of Alberta.

Some values set forth below may not add due to rounding.

It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material.

Reserves Data (Forecast Prices and Costs)

SUMMARY OF OIL AND GAS RESERVES AND NET PRESENT VALUES OF FUTURE NET REVENUE AS OF DECEMBER 31, 2018
FORECAST PRICES AND COSTS

	RESERVES									
	Light and Medium Oil		Solution Gas		Conventional Gas		Natural Gas Liquids		Total BOE	
Reserves Category	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)	Gross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)	Gross (Mboe)	Net (Mboe)
Proved										
Developed Producing	47	44	-	-	1,453,939	1,347,612	31,551	25,046	273,921	249,692
Developed Non-Producing	-	-	-	-	33,680	31,103	912	732	6,525	5,916
Undeveloped	-	-	-	-	1,202,600	1,120,865	35,447	30,774	235,880	217,584
Total Proved	47	44	-	-	2,690,218	2,499,580	67,910	56,552	516,327	473,192
Probable	16	14	-	-	1,423,977	1,322,357	49,137	40,769	286,482	261,176
Total Proved Plus Probable	63	58	-	-	4,114,195	3,821,937	117,047	97,321	802,809	734,369

Note:

(1) Numbers may not add due to rounding.

	NET PRESENT VALUES OF FUTURE NET REVENUE									
	Before Income Taxes Discounted at (%/year)					After Income Taxes Discounted at (%/year)				
Reserves Category	0 (M$)	5 (M$)	10 (M$)	15 (M$)	20 (M$)	0 (M$)	5 (M$)	10 (M$)	15 (M$)	20 (M$)
Proved										
Developed Producing	5,092,910	3,179,601	2,275,607	1,775,418	1,463,962	4,090,310	2,644,800	1,947,323	1,553,978	1,304,643
Developed Non-Producing	90,327	57,011	39,772	29,821	23,551	65,825	41,609	29,071	21,852	17,317
Undeveloped	3,782,073	1,792,634	943,063	517,271	279,955	2,757,267	1,261,717	619,301	298,340	121,528
Total Proved	8,965,310	5,029,247	3,258,442	2,322,509	1,767,468	6,913,401	3,948,126	2,595,695	1,874,170	1,443,489
Probable Additional	5,368,558	2,316,226	1,204,267	694,792	424,130	3,894,895	1,654,234	829,121	451,547	252,837
Total Proved Plus Probable	14,333,868	7,345,473	4,462,709	3,017,301	2,191,598	10,808,296	5,602,360	3,424,815	2,325,718	1,696,326

Note:

(1) Numbers may not add due to rounding.

TOTAL FUTURE NET REVENUE (UNDISCOUNTED) AS OF DECEMBER 31, 2018

Reserves Category	Revenue (M$)	Royalties (M$)	Operating Costs (M$)	Development Costs (M$)	Abandonment and Reclamation Costs[1] (M$)	Future Net Revenue Before Income Taxes (M$)	Income Taxes (M$)	Future Net Revenue After Income Taxes (M$)
Proved Reserves	16,225,518	1,454,987	3,485,216	1,971,004	349,001	8,965,310	2,051,909	6,913,401
Proved Plus Probable Reserves	26,142,789	2,479,154	5,411,188	3,445,031	473,548	14,333,868	3,525,571	10,808,296

Notes:

(1) Reflects estimated abandonment and reclamation for all wells (both existing and undrilled wells) that reserves have been attributed to. See "*Additional Information Concerning Abandonment and Reclamation Costs*".
(2) Numbers may not add due to rounding.

FUTURE NET REVENUE BY PRODUCT TYPE AS OF DECEMBER 31, 2018

Reserves Category	Product Type	Future Net Revenue Before Income Taxes (Discounted At 10%/Year) (M$)	($/bbl or $/Mcf)
Proved Reserves	Light and Medium Crude Oil[1]	1,446	36.28
	Heavy Oil[1]	-	-
	Natural Gas Liquids	-	-
	Conventional Natural Gas[2]	2,958,703	1.18
Proved Plus Probable Reserves	Light and Medium Crude Oil[1]	1,863	35.03
	Heavy Oil[1]	-	-
	Natural Gas Liquids	-	-
	Conventional Natural Gas[2]	4,081,458	1.07

Notes:

(1) Including solution gas and other by-products.
(2) Including by-products, but excluding solution gas and by-products from oil wells.
(3) Unit values are based on net reserve volumes.
(4) Net revenue does not include other income (i.e. processing income).

Definitions and Other Notes

In the tables set forth in this Statement and elsewhere in this Annual Information Form, the following definitions and other notes are applicable.

1. "**Gross**" means:

   (a) in relation to Peyto's interest in production and reserves, its "Peyto gross reserves", which are Peyto's interest (operating and non-operating) share before deduction of royalties and without including any royalty interest of Peyto;

   (b) in relation to wells, the total number of wells in which Peyto has an interest; and

   (c) in relation to properties, the total area of properties in which Peyto has an interest.

2. "**Net**" means:

   (a) in relation to Peyto's interest in production and reserves, its "Peyto net reserves", which are Peyto's interest (operating and non-operating) share after deduction of royalties obligations, plus Peyto's royalty interest in production or reserves;

   (b) in relation to wells, the number of wells obtained by aggregating Peyto's working interest in each of its gross wells; and

(c) in relation to Peyto's interest in a property, the total area in which Peyto has an interest multiplied by the working interest owned by Peyto.

3. Definitions used for reserve categories are as follows:

The following definitions apply to both estimates of individual reserves entities and the aggregate of reserves for multiple entities.

Reserve Categories

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on:

(a) analysis of drilling, geological, geophysical and engineering data;

(b) the use of established technology; and

(c) specified economic conditions (see the discussion of "*Economic Assumptions*" below).

Reserves are classified according to the degree of certainty associated with the estimates:

(a) Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

(b) Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

"Economic Assumptions" will be the prices and costs used in the estimate, namely forecast prices and costs.

Development and Production Status

Each of the reserve categories (proved and probable) may be divided into developed and undeveloped categories:

(a) Developed reserves are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing:

(i) Developed producing reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

(ii) Developed non-producing reserves are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

(b) Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable) to which they are assigned.

In multi-well pools it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

Levels of Certainty for Reported Reserves

The qualitative certainty levels referred to in the definitions above are applicable to individual reserve entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserves are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

(a) at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and

(b) at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves.

A qualitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

4. Forecast prices and costs

Future prices and costs that are:

(a) generally acceptable as being a reasonable outlook of the future; and

(b) if and only to the extent that, there are fixed or presently determinable future prices or costs to which Peyto is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

The forecast summary table under "*Statement of Reserves Data and Other Oil and Gas Information – Pricing Assumptions*" identifies benchmark reference pricing that apply to Peyto.

5. Future income tax expenses estimate:

(a) making appropriate allocations of estimated unclaimed costs and losses carried forward for tax purposes;

(b) without deducting estimated future costs that are not deductible in computing taxable income;

(c) taking into account estimated tax credits and allowances; and

(d) applying to the future pre-tax net cash flows relating to Peyto's oil and natural gas activities the appropriate year-end statutory rates, taking into account future tax rates already legislated.

6. "**Development costs**" means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and natural gas from reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground draining, road building, and relocating public roads, gas lines and power lines, pumping equipment and wellhead assembly;

(b) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and wellhead assembly;

(c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and

(d) provide improved recovery systems.

7. "**Development well**" means a well drilled inside the established limits of an oil and natural gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.

8. "**Exploration costs**" means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and natural gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(a) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies;

(b) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence, and the maintenance of land and lease records;

(c) dry hole contributions and bottom hole contributions;

(d) costs of drilling and equipping exploratory wells; and

(e) costs of drilling exploratory type stratigraphic test wells.

9. "**Exploration well**" means a well that is not a development well, a service well or a stratigraphic test well.

10. "**Service well**" means a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane or flue gas), water injection, steam injection, air injection, salt water disposal, water supply for injection, observation or injection for combustion.

11. Numbers may not add due to rounding.

12. The estimates of future net revenue presented in the tables above do not represent fair market value.

Pricing Assumptions

The following sets forth the benchmark reference prices, as at December 31, 2018, reflected in the Reserves Data. These price assumptions were provided to Peyto by InSite, Peyto's independent qualified reserves evaluator.

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS AS OF DECEMBER 31, 2018
FORECAST PRICES AND COSTS

	OIL				NATURAL GAS LIQUIDS					
Year	WTI Cushing Oklahoma ($US/bbl)	Edmonton Par Price 40° API ($Cdn/bbl)	Western Canada Select ($Cdn/bbl)	Natural Gas Aeco C Gas Price ($Cdn/MMBtu)	Condensate ($Cdn/bbl)	Butane ($Cdn/bbl)	Propane ($Cdn/bbl)	Ethane ($Cdn/bbl)	Inflation Rates(1) %/Year	Exchange Rate(2) ($US/$Cdn)
Forecast										
2019	57.00	63.50	47.75	1.90	67.95	20.96	28.58	5.30	2.0	1.316
2020	64.00	75.55	59.05	2.29	78.95	37.02	33.24	6.52	2.0	1.282
2021	68.00	80.50	65.50	2.71	83.72	45.89	37.03	7.82	2.0	1.250
2022	71.00	83.25	68.25	3.03	86.58	54.95	38.30	8.81	2.0	1.250
2023	72.80	85.60	70.60	3.21	88.60	58.21	41.52	9.38	2.0	1.250
2024	74.50	87.62	72.62	3.33	90.68	61.33	42.93	9.75	2.0	1.250
2025	76.50	90.01	74.51	3.44	93.16	62.10	44.10	10.09	2.0	1.250
2026	77.50	92.68	76.68	3.50	95.92	63.95	45.41	10.31	2.0	1.250
2027	79.05	94.53	78.53	3.57	97.84	65.22	46.32	10.53	2.0	1.250
2028	80.63	96.42	80.42	3.65	99.79	66.53	47.25	10.75	2.0	1.250
Thereafter	2%/yr	2%/yr	2%/yr	2%/yr	2%/yr	2%/yr	2%/yr	2%/yr	2.0	1.250

Notes:

(1) Inflation rates for forecasting prices and costs.
(2) Exchange rates used to generate the benchmark reference prices in this table.

Weighted average historical prices realized by Peyto for the year-ended December 31, 2018 were $2.54/Mcf for conventional natural gas and $56.98/bbl for crude oil and natural gas liquids.

Reconciliations of Changes in Reserves and Future Revenue

RECONCILIATION OF PEYTO GROSS (WORKING INTEREST) RESERVES BY PRINCIPAL PRODUCT TYPE FORECAST PRICES AND COSTS

	Light and Medium Crude Oil(1)			Conventional Natural Gas(2)			Natural Gas Liquids		
Factors	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)
December 31, 2017	75	29	104	2,439,258	1,355,763	3,795,021	44,656	44,433	89,089
Extensions	-	-	-	230,284	135,220	365,504	10,597	8,151	18,748
Improved Recovery	-	-	-	-	-	-	-	-	-
Technical Revision	6	-2	4	69,780	8,419	78,199	11,700	-2,329	9,371
Infill Drilling	-	-	-	69,902	6,846	76,748	3,101	583	3,685
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-
Category Transfer	-	-	-	77,467	-77,467	-	1,561	-1,561	-
Economic Factors	-	-	-	-16,366	-4,867	-21,233	-177	-142	-319
Production	-12	-	-12	-180,248	-	-180,248	-3,531	-	-3,531
December 31, 2018	70	27	96	2,690,076	1,423,915	4,113,991	67,907	49,136	117,042

Notes:

(1) Including solution gas and other by-products.
(2) Including by-products, but excluding solution gas and by-products from oil wells.
(3) Unit values are based on net reserve volumes.
(4) Numbers may not add due to rounding.

RECONCILIATION OF PEYTO NET RESERVES (NET OF ROYALTIES) BY PRINCIPAL PRODUCT TYPE FORECAST PRICES AND COSTS

	Light and Medium Crude Oil[1]			Conventional Natural Gas[2]			Natural Gas Liquids		
Factors	Net Proved (Mbbl)	Net Probable (Mbbl)	Net Proved Plus Probable (Mbbl)	Net Proved (MMcf)	Net Probable (MMcf)	Net Proved Plus Probable (MMcf)	Net Proved (Mbbl)	Net Probable (Mbbl)	Net Proved Plus Probable (Mbbl)
December 31, 2017	70	27	97	2,256,095	1,242,841	3,498,937	36,664	37,247	73,911
Extensions	-	-	-	214,117	124,159	338,276	9,000	6,408	15,408
Improved Recovery	-	-	-	-	-	-	-	-	-
Technical Revision	4	-2	1	76,351	26,686	103,036	9,988	-1,812	8,176
Infill Drilling	-	-	-	65,846	5,715	71,560	2,689	446	3,135
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-
Category Transfer	-	-	-	72,580	-72,580	-	1,403	-1,403	-
Economic Factors	-	-	-	-15,204	-4,521	-19,726	-147	-118	-266
Production	-10	-	-10	-170,335	-	-170,335	-3,047	-	-3,047
December 31, 2018	64	24	88	2,499,449	1,322,298	3,821,748	56,550	40,768	97,318

Notes:

(1) Including solution gas and other by-products.
(2) Including by-products, but excluding solution gas and by-products from oil wells.
(3) Unit values are based on net reserve volumes.
(4) Numbers may not add due to rounding.

Additional Information Relating to Reserves Data

Undeveloped Reserves

The following tables set forth the proved undeveloped reserves and the probable undeveloped reserves, each by product type, attributed to the Corporation in the three most recent financial years.

Proved Undeveloped Reserves

Peyto's proved undeveloped reserves are comprised mainly of wells that are budgeted and scheduled to be drilled in the next five years. Peyto also has proved undeveloped reserves behind pipe (mostly up-hole zones) which will be brought on production once the primary zones have been depleted. Where there is economical justification to accelerate production from secondary zones, Peyto will often proceed to re-complete the subject well bores or drill twin wells for secondary zones.

	Light and Medium Crude Oil[1] (Mbbl)		Conventional Natural Gas[2] (MMcf)		Natural Gas Liquids (Mbbl)	
Year	1st Attributed	Cumulative at Year-End [1]	1st Attributed	Cumulative at Year-End [1]	1st Attributed	Cumulative at Year-End [1]
2016	-	-	164,756	753,255	1,784	12,448
2017	-	-	225,751	854,114	3,019	14,238
2018	-	-	275,815	1,120,865	10,219	30,774

Notes:

(1) Including solution gas and other by-products.
(2) Including by-products, but excluding solution gas and by-products from oil wells.
(3) Unit values are based on net reserve volumes.
(4) Cumulative at Year-End = Residual Cumulative of Previous Year plus 1st Attributed.

Probable Undeveloped Reserves

Peyto's probable additional reserves are comprised of performance wedges from producing wells (approximately 22%), step out drilling locations and bypassed zones, which are deemed too probabilistic to be classified as proved. Peyto typically assigns probable reserves to undrilled locations that are scheduled to be drilled in the next five to seven years. Peyto has historically been successful converting these probable assignments to proven producing entities.

	Light and Medium Crude Oil(1) (Mbbl)		Conventional Natural Gas(2) (MMcf)		Natural Gas Liquids (Mbbl)	
Year	1st Attributed	Cumulative at Year-End (1)	1st Attributed	Cumulative at Year-End (1)	1st Attributed	Cumulative at Year-End (1)
2016	-	-	246,848	853,823	4,177	13,082
2017	-	-	201,159	865,620	4,180	18,161
2018	-	-	84,272	883,325	3,537	21,149

Notes:

(1) Including solution gas and other by-products.
(2) Including by-products, but excluding solution gas and by-products from oil wells.
(3) Unit values are based on net reserve volumes.
(4) Cumulative at Year-End = Residual Cumulative of Previous Year plus 1st Attributed.

Significant Factors or Uncertainties

The process of evaluating reserves is inherently complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and natural gas prices and costs change. The reserve estimates contained herein are based on current production forecasts, prices and economic conditions and other factors and assumptions that may affect the reserve estimates and the present worth of the future net revenue therefrom. These factors and assumptions include, among others: (i) historical production in the area compared with production rates from analogous producing areas; (ii) initial production rates; (iii) production decline rates; (iv) ultimate recovery of reserves; (v) success of future development activities; (vi) marketability of production; (vii) effects of government regulations; and (viii) other government levies imposed over the life of the reserves.

As circumstances change and additional data becomes available, reserve estimates also change. Estimates are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and government restrictions. Revisions to reserve estimates can arise from changes in year-end prices, reservoir performance and geologic conditions or production. These revisions can be either positive or negative.

While we do not anticipate any significant economic factors or significant uncertainties will affect any particular components of the reserves data, the reserves can be affected significantly by fluctuations in product pricing, capital expenditures, operating costs, royalty regimes and well performance that are beyond our control. See "*Risk Factors*".

Future Development Costs

The following table sets forth development costs deducted in the estimation of Peyto's future net revenue attributable to the reserve categories noted below.

	Forecast Prices and Costs	
	Proved Reserves	Proved Plus Probable Reserves
Year	0% (M$)	0% (M$)
2019	158,044	200,132
2020	164,554	349,938
2021	319,386	400,274
2022	430,784	700,240
2023	403,201	650,131
Thereafter	495,035	1,144,316
Total Undiscounted	1,971,004	3,445,031
Change from 2017	482,707	466,943

Peyto anticipates that funding for the future development costs will include internally generated cash flow, debt and equity financing.

2018 Finding, Development and Acquisition Costs
Company Interest Reserves
(Forecast Prices and Costs)

Finding, Development and Acquisition Costs Including Changes in Future Development Capital ("**FDC**")	Proved Developed Producing Reserves	Proved Reserves	Proved Plus Probable Reserves
Exploration and Development Capital Expenditures (M$)	230,413	230,413	230,413
Exploration and Development Change in FDC (M$)	-	482,700	466,900
Exploration and Development Capital including Change in FDC (M$)	230,413	713,113	697,313
Exploration and Development Reserve Additions including Revisions (Mboe)(1)	32,954	98,637	114,697
Finding and Development Cost ($/BOE)(1)	6.99	7.23	6.08
Net Acquisition Capital (M$)	1,950	1,950	1,950
Net Acquisition Reserve Additions (Mboe)(1)	-	-	-
Net Acquisition Cost ($/BOE)(1)	-	-	-
Total Capital Expenditures including Net Acquisitions (M$)	232,363	232,363	232,363
Total Changes in FDC (M$)	-	482,700	466,900
Total Capital including Change in FDC (M$)	232,363	715,063	699,263
Reserve Additions including Revisions and Net Acquisitions (Mboe)(1)	32,954	98,637	114,697
Finding, Development and Acquisition Cost including Change in FDC ($/BOE)(1)	7.05	7.25	6.10

Note:

(1) Natural gas has been converted to barrels of oil equivalent on the basis of 6 Mcf of natural gas being equal to one barrel of oil.

Three Year Historical Finding, Development and Acquisition Costs
$/BOE

Year	Proved Developed Producing	Total Proved	Total Proved Plus Probable
2016	8.62	6.04	3.74
2017	8.16	8.35	8.97
2018	7.05	7.25	6.10
Three Year Average	7.94	7.21	6.27

The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year. The use of boes may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the well head. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6 Mcf:1 bbl, utilizing a conversion on a 6 Mcf:1 bbl basis may be misleading as an indication of value.

Other Oil and Gas Information

Oil and Gas Properties

The following is a description of Peyto's principal oil and natural gas properties on production or under development as at December 31, 2018. The term "net", when used to describe Peyto's share of production, means the total of Peyto's working interest share before deduction of royalties owned by others. Reserve amounts are stated, before deduction of royalties, at December 31, 2018, based on escalating cost and price assumptions (gross) as evaluated in the InSite Report (see "*Statement of Reserves Data and Other Oil and Gas Information*"). Unless otherwise specified, gross and net acres and well count information are as at December 31, 2018. Information in respect of current production is average production, net to Peyto, for the month of February 2019, except where otherwise indicated. The estimate 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.

General

Peyto operates in three core areas, namely the Greater Sundance, Brazeau River areas and Northern area of Alberta. Within the Greater Sundance area there are four sub-areas, Sundance, Nosehill, Wildhay and Ansell, all of which have Peyto operated gas processing facilities that are interconnected. Total capital expenditures for 2018 were $232.3 million. In total, Peyto anticipates investing $150 to $200 million and plans to drill approximately 50 net wells with a focus on the Cardium liquids-rich resource play in 2019.

Greater Sundance Area

The Greater Sundance area is located 50 kilometers west of Edson, Alberta, from Township 50–56 and Range 19-24 west of the fifth meridian. Peyto began its operations in this area in the spring of 1999. This area now encompasses the Sundance, Wildhay, Nosehill and Ansell fields and is generally referred to as the "Greater Sundance area".

Peyto has an average 78.3% working interest in 333,120 gross (260,850 net) acres of land and operates 99% of its production in the area.

The geology of the area is characterized by multi-zone potential for liquids-rich natural gas. Peyto currently produces gas from the Belly River, Cardium, Viking, Notikewin, Falher, Wilrich, Bluesky and Cadomin formations.

During 2018, Peyto spent $193 million in capital to drill, case, complete, equip and tie-in 57 new net wells in the Greater Sundance area. Included in this capital is Peyto's proportionate share of land and seismic acquisition costs as well as plant costs. Peyto is currently producing approximately 66,600 boe/d of natural gas and natural gas liquids from this area. The Greater Sundance area includes several properties that collectively accounted for:

- 83% of 2018 capital expenditures
- 75% of 2018 production volume
- 79% of proved and probable reserves at December 31, 2018
- 41% of undeveloped land holding at December 31, 2018

Peyto currently plans to invest the majority of the 2019 capital budget drilling Cardium horizontal wells in this area.

Peyto owns and operates five 100% working interest gas processing plants and one joint plant (89% working interest at December 31, 2018) located in the Greater Sundance area. Two of the plants are located in Oldman (55-21W5), the third one is located in Wildhay (55-23W5), the fourth one is located in Nosehill (55-20W5) and the fifth and sixth plants are located in Ansell (53-20W5 and 53-19W5). The majority of Peyto's production is processed through these plants, with 1,365 gross (1,223 net) producing zones currently tied-in. Gross natural gas production at the facilities is approximately 398 MMcf/d, with gross natural gas liquids production being approximately 9,800 bbls/d.

Brazeau River

The Brazeau River area is located 180 km southwest of Edmonton, Alberta, from Township 41-44 and Range 11-14 west of the fifth meridian. Peyto began operations in this area in late 2013.

Peyto has an average 94% working interest in 121,920 gross (114,491 net) acres of land and operates 99% of its production in the area.

The geology of the area indicates multi-zone potential for liquids-rich natural gas. Peyto currently produces gas from the Notikewin, Belly River, Wilrich, Falher and Cardium formations.

In 2018, Peyto drilled and completed 6 gross (6 net) wells in Brazeau. Peyto is currently producing approximately 15,540 boe/d of gross natural gas and natural gas liquids from this area. The Brazeau area accounted for:

- 10% of 2018 capital expenditures
- 21% of 2018 production volume
- 14% of proved and probable reserves at December 31, 2018
- 28% of undeveloped land holding at December 31, 2018

Peyto owns a 100% working interest in and operates its gas processing plant in Brazeau. The majority of the production from the area is processed through this plant with 107 producing zones currently tied in. Gross production from this facility is approximately 84 MMcf/d of natural gas with approximately 1,500 bbls/d of natural gas liquids.

Northern Area

The Northern area includes producing properties in the following regions: Smoky, Kakwa, Chime, Kiskiu, Chicken and Cutbank and it encompasses Townships 57-64 and Ranges 2-7 west of the sixth meridian. The Kakwa gas plant, which services producing properties in Smoky, Kakwa, Chime and Kiskiu (together referred to as "**Greater Kakwa**") is located 40 km northeast of Grande Cache, Alberta. Peyto began operations in this area in the winter of 2002/2003.

Peyto has an average 90% working interest in 95,360 gross (86,111 net) acres of land and operates 97% of its production in the area.

The geology of the area indicates multi-zone potential for liquids-rich natural gas. Peyto currently produces gas from the Belly River, Dunvegan, Chinook and Cardium formations. The majority of Peyto's current production comes from the Cardium formation, which exists as a low permeability blanket sand.

In 2018, Peyto drilled and completed 1 gross (1 net) Cardium well in the Northern area. Peyto is currently producing approximately 2,790 boe/d of gross natural gas and natural gas liquids from this area. The Northern area accounted for:

- 3% of 2018 capital expenditures
- 2% of 2018 production volume
- 5% of proved and probable reserves at December 31, 2018
- 19% of undeveloped land holding at December 31, 2018

Peyto owns a 100% working interest in and operates its gas processing plant in Smoky/Kakwa. The majority of Peyto's production from the area is processed through this plant with 61 producing zones currently tied in. Gross production from this facility is approximately 12 MMcf/d of natural gas with approximately 715 bbls/d of natural gas liquids.

Peyto owns a 100% working interest in and operates its gas processing plant in Cutbank. The majority of the production around the Cutbank area is processed through this plant with 15 producing zones currently tied in. Gross production from this facility is approximately 935 Mcf/d of natural gas with approximately 11 bbls/d of natural gas liquids.

Miscellaneous

Peyto has a number of minor working interests in non-operated wells throughout Alberta. These properties account for less than 1% of Peyto's current production. The anticipated capital spending for these areas is minimal.

Oil and Gas Wells

The following table sets forth the number and status of wells in which Peyto had a working interest as at December 31, 2018.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing(1)	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	5	2.65	5	1.22	1,539	1,341.4	175	129.6
British Columbia	-	-	-	-	1	-	6	0.3
Total	5	2.65	5	1.22	1,540	1,341.4	181	129.9

Note:

(1) The non-producing oil wells and natural gas wells capable of production but which are not currently producing will be re-evaluated with respect to future product prices, proximity to facility infrastructure, design of future exploration and development programs and access to capital.

Land Holdings

The following table sets out Peyto's developed and undeveloped land holdings as at December 31, 2018.

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Alberta	216,320	176,604	381,760	325,381	598,080	501,986
British Columbia	4,793	265	3,773	147	8,565	412
Total	221,113	176,870	385,533	325,528	606,645	502,397

Note:

(1) Numbers may not add due to rounding.

Peyto expects that rights to explore, develop and exploit 6,560 net acres of its undeveloped land holdings will expire by December 31, 2019.

Hedging Contracts

Peyto is a party to certain off balance sheet derivative financial instruments, including fixed price contracts and physical delivery contracts. Peyto enters into these contracts with well established counter-parties for the purpose of protecting a portion of its future revenues from the volatility of oil and natural gas prices.

A summary of contracts outstanding, as at December 31, 2018, in respect of the hedging activities is included in Note 13 to Peyto's audited financial statements for the year ended December 31, 2018, which are available on SEDAR at www.sedar.com.

Tax Horizon

No material cash income taxes were paid by Peyto for the year ended December 31, 2018. Within the context of current commodity prices and capital spending plans, Peyto does not expect to be taxable before 2022. This future tax horizon will also fluctuate depending on the ultimate nature and timing of Peyto's acquisitions and dispositions. If crude oil and natural gas prices were to strengthen beyond the levels anticipated by the current forward market, Peyto's tax pools would be utilized more quickly and it may experience higher than expected cash taxes or payment of such taxes in an earlier time period. However, it is difficult to give guidance on future taxability as Peyto operates within an industry that constantly changes given acquisitions, divestments, capital spending, dividends and overall commodity prices. See "*Risk Factors*".

Additional Information Concerning Abandonment and Reclamation Costs

Peyto bases its estimates for the costs of abandonment and reclamation of surface leases, wells and facilities on previous experience of management with similar well sites and facility locations. As at December 31, 2018, management expected to incur such costs on 1,475.2 net wells and 8.9 net facilities. The total of such costs, net of estimated salvage value, expected to be incurred is $301.8 million (undiscounted) and $153.9 million (discounted at 2.18%). These estimated abandonment and reclamation costs do not include any locations for undrilled wells. Within the next three financial years, it is expected such abandonment and reclamation costs will total approximately $1.3 million (undiscounted) in aggregate.

For the purposes of estimating the Reserves Data, abandonment and reclamation costs for all wells (both existing and undrilled wells) that have been attributed reserves have been taken into account. No allowance was made, however, for the abandonment and reclamation of any pipelines or facilities or for wells with no attributed reserves. Future net revenue figures set forth in this Statement only include abandonment and reclamation liabilities for wells that have been assigned reserves.

Using public data and the Corporation's own experience, Peyto estimates the amount and timing of future abandonment and reclamation expenditures at an operating area level. Wells within each operating area are assigned an average cost per well to abandon and reclaim the well. The estimated expenditures are based on current regulatory standards and actual abandonment and reclamation cost history.

Additional information related to our estimated share of future environmental and reclamation obligations for the working interest properties (including all abandonment and reclamation costs associated with all existing wells, facilities, pipelines and leases) can be found in Peyto's audited financial statements for the year ended December 31, 2018 and the accompanying management's discussion and analysis, which are available on SEDAR at www.sedar.com.

Capital Expenditures

The following table summarizes capital expenditures (net of incentives and net of certain proceeds and including capitalized general and administrative expenses) related to Peyto's activities for the year-ended December 31, 2018.

Property acquisition (disposition) costs			
Proved properties	MM	$	2.0
Unproved properties			3.3
Exploration costs			21.6
Development costs			205.3
Total	MM	$	232.2

Exploration and Development Activities

The following table sets forth the gross and net exploratory and development wells in which Peyto participated during the year-ended December 31, 2018.

	Exploratory Wells		Development Wells	
	Gross	Net	Gross	Net
Oil	-	-	-	-
Natural Gas	3.0	3.0	67	64.25
Service	-	-	-	-
Dry	-	-	-	-
Total:	3.0	3.0	67	64.25

For a description of Peyto's most important current and likely exploration and development activities, see "*Statement of Reserves Data and Other Oil and Gas Information – Other Oil and Gas Information – Oil and Gas Properties*".

Production Estimates

The following table sets out the volume of Peyto's production before royalties estimated for the year-ended December 31, 2019 which is reflected in the estimate of gross proved reserves and probable reserves disclosed in the tables contained under "*Statement of Reserves Data and Other Oil and Gas Information – Disclosure of Reserves Data*".

	Light and Medium Crude Oil(1)	Conventional Natural Gas(2)	Natural Gas Liquids	BOE
	(bbls/d)	*(MMcf/d)*	*(bbls/d)*	*(boe/d)*
Proved				
Greater Sundance	5	342	8,445	65,438
Brazeau	-	77	1,348	14,147
Northern Area	9	13	794	2,980
Other	2	10	310	2,060
Total Proved 2019	16	442	10,897	84,625
Proved Plus Probable				
Greater Sundance	5	356	9,001	68,323
Brazeau	-	80	1,412	14,719
Northern Area	9	15	917	3,366
Other	-	11	328	2,174
Total Proved Plus Probable 2019	16	461	11,658	88,582

Notes:

(1) Including solution gas and other by-products.
(2) Including by-products, but excluding solution gas and by-products from oil wells.
(3) Unit values are based on net reserve volumes.
(4) Numbers may not add due to rounding.

Production History and Prices Received

The following table summarizes certain information in respect of production, product prices received, royalties paid, operating expenses and resulting netback for the periods indicated below.

	2018			
	Quarter Ended			
	Dec. 31	Sept. 30	June 30	March 31
Average Daily Production[1]				
Light and Medium Crude Oil (bbls/d)[2]	-	-	-	-
Conventional Natural Gas (Mcf/d)[3]	458,792	456,197	493,821	568,496
NGLs (bbls/d)	10,273	9,209	9,243	10,043
Combined (boe/d)	86,738	85,242	91,547	104,793
Average Price Received				
Light and Medium Crude Oil ($/bbl)[2]	-	-	-	-
Conventional Natural Gas ($/Mcf)[3]	2.43	2.43	2.37	2.86
NGLs ($/bbl)	44.83	61.04	63.64	59.67
Combined ($/McfGE)	3.03	3.27	3.20	3.54
Royalties Paid ($/McfGE)	0.12	0.14	0.10	0.17
Production Costs including Transportation ($/McfGE)	0.52	0.50	0.48	0.42
Netback Received ($/McfGE)	2.39	2.63	2.62	2.95

Notes:

(1) Before deduction of royalties.
(2) Including solution gas and other by-products.
(3) Including by-products, but excluding solution gas and by-products from oil wells.
(4) Unit values are based on net reserve volumes.
(5) Numbers may not add due to rounding.

The following table indicates Peyto's average daily production from its important fields, and in total, for the year-ended December 31, 2018.

	Light and Medium Crude Oil[1]	Conventional Natural Gas[2]	NGLs	BOE
	(bbls/d)	(MMcf/d)	(bbls/d)	(boe/d)
Greater Sundance	5	371	7,193	69,072
Brazeau	-	104	1,715	19,014
Northern Area	8	9	483	2,021
Other Properties	2	10	286	1,905
Total Alberta	15	494	9,677	92,012
Total British Columbia	-	-	-	-
Total	15	494	9,677	92,012

Notes:

(1) Including solution gas and other by-products.
(2) Including by-products, but excluding solution gas and by-products from oil wells.
(3) Unit values are based on net reserve volumes.
(4) Numbers may not add due to rounding.

DIVIDENDS

In conjunction with the completion of the 2010 Arrangement, the board of directors of the Corporation established a dividend policy of paying monthly dividends to the holders of Common Shares. The payment of dividends by the Corporation commenced with the first dividend declared to Shareholders of record on January 31, 2011 in the amount of $0.06 per Common Share, made payable February 15, 2011. It is expected that cash dividends will continue to be made by the Corporation on approximately the 15th day of each month to holders of Common Shares of record on the immediately preceding dividend record date.

Peyto's policy is to balance dividends to Shareholders with earnings and cash flow; and balance funding for the capital program with cash flow, equity and available bank lines. The board of directors of the Corporation is prepared to adjust the payout ratio levels (dividends declared divided by funds from operations) to achieve the desired dividends while maintaining an appropriate capital structure. See "*Risk Factors – Dividends*".

The Corporation's credit facility and the terms of its outstanding senior unsecured notes ("**Senior Notes**") of the Corporation, including the 2015 Senior Notes, the 2016 Senior Notes, the 2018 Senior Notes and the 2019 Senior Notes and the other senior unsecured notes described in Note 5 to Peyto's audited financial statements for the year ended December 31, 2018, which are available on SEDAR at www.sedar.com, provide that if the Corporation is in default under the credit facility or the Senior Notes, as applicable, the indebtedness may be accelerated by the lenders, and the ability to pay dividends to Shareholders may be restricted. Dividends are only permitted under the credit facility and the terms of the Senior Notes when no event of default under the credit facility or the Senior Notes, as applicable, has occurred and is continuing.

Dividend History

Following the 2010 Arrangement, the following dividends were paid by the Corporation to Shareholders for the periods indicated:

For the Year Ended	Aggregate Annual Dividend per Common Share
2011	$0.72
2012	$0.72
2013	$0.88
2014	$1.14
2015	$1.32
2016	$1.32
2017	$1.32
2018	$0.72

On January 16, 2019, Peyto announced that, starting with the January 2019 dividend, the Corporation's monthly dividend would be temporarily reduced from $0.06 per Common Share to $0.02 per Common Share. See "*General Development of the Business – Three Year History – Recent Developments*".

DESCRIPTION OF SHARE CAPITAL

Peyto is authorized to issue an unlimited number of Common Shares. Holders of Common Shares are entitled to one vote per share at meetings of Shareholders, to receive dividends if, as and when declared by the board of directors of Peyto and to receive pro rata the remaining property and assets of Peyto upon its dissolution or winding-up, subject the rights of shares having priority over the Common Shares.

MARKET FOR SECURITIES

Common Shares

The Common Shares commenced trading on the TSX under the symbol "PEY" on January 7, 2011 following completion of the 2010 Arrangement. The following table sets forth the trading history of the Common Shares for the periods indicated as reported by the TSX.

	Price Range		
	High ($)	Low ($)	Volume
2019			
January	8.03	6.49	28,407,506
February	8.00	6.62	13,608,512

	Price Range		
	High ($)	Low ($)	Volume
March (1 to 15)	7.90	6.94	9,062,499
2018			
January	15.83	11.10	30,231,738
February	12.13	9.83	20,258,075
March	11.33	9.93	23,424,501
April	12.69	10.52	18,168,194
May	12.38	10.22	18,145,157
June	10.84	9.95	18,690,916
July	11.40	10.02	14,185,795
August	11.25	9.87	16,056,367
September	11.43	10.08	16,994,058
October	12.44	10.60	17,813,645
November	11.88	10.10	21,638,270
December	10.53	6.59	26,701,900

ESCROWED SECURITIES

There are no securities of the Corporation currently held in escrow.

DIRECTORS AND OFFICERS OF PEYTO

The name, municipality of residence, principal occupation for the current year and prior years of each of the current directors and officers of Peyto are set forth below.

Name and Municipality of Residence	Position with Peyto	Principal Occupation
Donald Gray Scottsdale, Arizona United States	Director since 1998 and Chairman of the Board since 2009	Private Investor; Chairman of Gear Energy Ltd., a public oil and natural gas company, since January 2010; Chairman of the Board of Petrus Resources Ltd., a public oil and gas company, since 2010; Mr. Gray was the President of EIQ Capital Corp., a private capital management company, from May 2007 to September 2017; prior thereto, Mr. Gray was the Chief Executive Officer of Peyto from August 2006 to January 2007; prior thereto, Mr. Gray was the President and Chief Executive Officer of Peyto from October 1998 to August 2006
Michael MacBean[(1)(2)(3)] Calgary, Alberta Canada	Director since 2003 and Lead Independent Director since 2009	Senior Managing Director of TriWest Capital Partners since May 12, 2010; prior thereto, Chief Executive Officer of Diamond Energy Services LP, an energy services partnership, since October 1998
Brian Davis[(1)(2)(3)] Houston, Texas United States	Director since 2006	Managing Partner of Oil and Gas Evaluations and Consulting, an independent oil and gas engineering consultancy firm based in Houston, Texas, since July 1994
Gregory Fletcher[(1)(2)(3)] Calgary, Alberta Canada	Director since 2007	President of Sierra Energy Inc., a private oil and gas production company, since 1997
Darren Gee Calgary, Alberta Canada	President, Chief Executive Officer and Director since 2007	President and Chief Executive Officer of Peyto since January 2007 and President of Peyto since August 2006; prior thereto, Mr. Gee was the Vice President, Engineering of Peyto from March 2001 to August 2006

Name and Municipality of Residence	Position with Peyto	Principal Occupation
Stephen J. Chetner Calgary, Alberta Canada	Corporate Secretary since 2000 and Director since 2009	Partner of Burnet, Duckworth & Palmer LLP
Kathy Turgeon Calgary, Alberta Canada	Vice President, Finance and Chief Financial Officer and Director since May 2018	Vice President, Finance and Chief Financial Officer since November 30, 2007; prior thereto Vice President, Finance of Peyto from January 2006 to November 2007; prior thereto, Ms. Turgeon was the Controller of Peyto from April 2004 to January 2006
Timothy Louie Calgary, Alberta Canada	Vice President, Land	Vice President, Land of Peyto since January 2012; prior thereto, Mr. Louie was Land Manager of Daylight Energy Ltd. from April 2005 to December 2011
Jean-Paul (JP) Lachance Calgary, Alberta Canada	Vice President, Engineering and Chief Operating Officer	Vice President, Engineering and Chief Operating Officer since February 1, 2018; prior thereto, Vice President, Exploitation of Peyto from September 2011 to February 1, 2018; prior thereto, Mr. Lachance was the Vice President, Engineering of ProspEx Resources Ltd. from October 2004 to May 2011
David Thomas Calgary, Alberta Canada	Vice President, Exploration	Vice President, Exploration of Peyto since November 1, 2010; prior thereto, Senior Geologist with Peyto since 2005
Lee Curran Calgary, Alberta Canada	Vice President, Drilling and Completions	Vice President, Drilling and Completions of Peyto since January 1, 2015; prior thereto, drilling engineer with Peyto since 2006; promoted to Drilling Manager with Peyto from May 2011 to January 2015
Todd Burdick Calgary, Alberta Canada	Vice President, Production	Vice President, Production of Peyto since January 1, 2015; prior thereto, production engineer with Peyto since 2004; promoted to Production Manager with Peyto from January 2010 to January 2015

Notes:

(1) Member of the Audit Committee.
(2) Member of the Compensation and Nominating Committee.
(3) Member of the Reserves Committee.
(4) Peyto does not have an executive committee.
(5) Peyto directors shall hold office until the next annual general meeting of the Shareholders or until each director's successor is appointed or elected pursuant to the ABCA.
(6) The period of time served as a director or officer of Peyto includes the period of time served as a director of Peyto AdminCo or an officer of PEDC, where and as applicable, prior to the completion of the 2010 Arrangement.

As at March 28, 2019, the directors and executive officers of Peyto, as a group, beneficially owned, directly or indirectly, or exercised control or direction over 4.7 million Common Shares, or approximately 3% of the issued and outstanding Common Shares.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

Other than as disclosed below, no director or officer of Peyto, or a shareholder holding a sufficient number of securities of Peyto to affect materially the control of Peyto is, as at the date hereof, or has been within the 10 years before the date hereof, a director, or executive officer of any company that: (i) while such person was acting in that capacity, was the subject of a cease trade or similar order or an order that denied the relevant company access to any exemption under securities legislation for a period of more than 30 consecutive days; (ii) was subject to an event that resulted, after the director or executive officer ceased to be a director or executive officer, in the company being the subject of a cease trade or similar order or an order that denied the relevant company any exemption under securities legislation, for a period of more than 30 consecutive days; or (iii) while such person was acting in that capacity or within a year of such 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.

Mr. Darren Gee, a director, President and Chief Executive Officer of Peyto, was a director of Endurance Energy Ltd. ("**Endurance**"), a corporation engaged in the exploration and production of natural gas. Mr. Gee resigned as a director of Endurance on September 1, 2015. Nine months after Mr. Gee's resignation, Endurance filed for creditor protection under the *Companies Creditors' Arrangement Act* on May 30, 2016.

No director or officer of Peyto, or a shareholder holding a sufficient number of securities of Peyto to affect materially the control of Peyto (or any personal holding company of such person), has been subject to any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority or 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.

Personal Bankruptcies

No director or officer of Peyto, or a shareholder holding sufficient securities of Peyto to affect materially the control of Peyto, or a personal holding company of any such persons, has, within the 10 years preceding the date of this document, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or became subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold the assets of the individual.

Conflicts of Interest

There are potential conflicts of interest to which the directors and officers of Peyto will be subject in connection with the operations of Peyto. In particular, certain of the directors and officers of Peyto are involved in managerial or director positions with other oil and natural gas companies whose operations may, from time to time, be in direct competition with those of Peyto or with entities which may, from time to time, provide financing to, or make equity investments in, competitors of Peyto. Conflicts, if any, will be subject to the procedures and remedies available under the ABCA. The ABCA provides that in the event a director has an interest in a contract or proposed contract or agreement, the director shall disclose his interest in such contract or agreement and shall refrain from voting on any matter in respect of such contract or agreement unless otherwise provided in the ABCA. As at the date hereof, Peyto is not aware of any existing material conflicts of interest between Peyto and any director or officer of Peyto.

Personnel

As at December 31, 2018, Peyto, directly or indirectly, employed 53 head office employees. Contract operators are retained for all field operations.

Audit Committee

Members

The Audit Committee currently has three members, Michael MacBean (Chairman), Brian Davis and Gregory Fletcher, none of whom have a direct or indirect material relationship with Peyto and each of whom is financially literate, meaning the individual has the ability to read and understand a set of financial statements that present a breadth and level of complexity of the issues that can be expected to be raised by Peyto's financial statements.

The following is a description of the education and experience of each member of the Audit Committee.

Michael MacBean

Mr. MacBean is the Chairman of the Audit Committee and the Corporation's independent lead director. Mr. MacBean is primarily engaged as a Senior Managing Director of TriWest Capital Partners and, prior thereto, was Chief Executive Officer of Diamond Energy Services LP, a partnership engaged in the energy services sector. Mr. MacBean is also a director of Source Energy Services Ltd., a public oilfield service company, and a director of TerraVest Industries Inc., a public industrial product manufacturing company. From 1995 through 1998, Mr. MacBean served as Controller and subsequently Senior Investment Analyst for ARC

Financial Corporation. During this time Mr. MacBean also served as Vice President, Finance for ARC Energy Trust. Mr. MacBean received his Bachelor of Commerce Degree from the University of Saskatchewan in 1990. In 1993, Mr. MacBean received his Chartered Accountant designation from the Institute of Chartered Accountants of Alberta. In February 2007, Mr. MacBean received his Chartered Directors (C.Dir) designation from McMaster University.

Brian Davis

Mr. Davis is the Chairman of the Reserves Committee. Mr. Davis is primarily engaged as the Managing Partner of Oil and Gas Evaluations and Consulting, an independent oil and gas engineering consultancy firm based in Houston, Texas, since July 1994. In his role, Mr. Davis has acquired significant experience and exposure to accounting and financial issues. Mr. Davis holds a BSc in petroleum engineering from Texas A&M University.

Gregory Fletcher

Mr. Fletcher is the Chairman of the Compensation & Nominating Committee. Mr. Fletcher is primarily engaged as the President of Sierra Energy Inc., a private oil and gas production company that he founded in 1997. Mr. Fletcher is also a director of Calfrac Well Services Ltd., a public oilfield service company, and a director of Whitecap Resources Inc., a public oil and gas company. In these roles, Mr. Fletcher has acquired significant experience and exposure to accounting and financial reporting issues. Mr. Fletcher holds a BSc in geology from the University of Calgary. In January 2009, Mr. Fletcher graduated from the Directors' Education Program sponsored by the Institute of Corporate Directors and the Haskayne School of Business.

Charter

The primary function of the Audit Committee is to assist the board of directors in fulfilling its oversight responsibilities for financial matters. It performs this function by serving as an independent and objective party to monitor Peyto's financial reporting process and internal control system; reviewing and assessing audit efforts of Peyto's independent auditors; providing an avenue of open communication among Peyto's independent auditors, financial and senior management and board of directors; and reviewing the independence and performance of the independent auditor. The Audit Committee has the authority to conduct or authorize investigations into any matters within the scope of its responsibilities and the authority to retain such outside counsel, experts and other advisors as it determines appropriate to assist in the conduct of any investigation. Attached as Schedule C hereto is the complete text of the Audit Committee's Charter.

Audit Fees

The table below provides disclosure of the fees billed to Peyto by its external auditors in fiscal 2018 and fiscal 2017, dividing the services into the categories of work performed.

Type of Work	2018 Fees	2018 Percentage	2017 Fees	2017 Percentage
Audit Fees	$200,000	66%	$180,000	60%
Audit Related Fees				
Review of interim financial statements and MD&A, reviewing prospectus disclosures	$54,000	18%	$54,000	18%
Extractive Sector Transparency Measures Act (ESTMA)	-	-	$13,725	5%
Insurance Advisory	$40,000	13%	$44,800	15%
Tax Fees				
Tax compliance services, tax advice, tax planning and annual filings	$10,000	3%	$5,450	2%
Total	$304,000		$297,975	

All non-audit services are disclosed and approved by the Audit Committee.

INDUSTRY CONDITIONS

Companies carrying on business in the crude oil and natural gas sector in Canada are subject to extensive controls and regulations imposed through legislation of the federal government and the provincial governments where the companies have assets or operations. While these regulations do not affect the Corporation's operations in any manner that is materially different than the manner in which they affect other similarly-sized industry participants with similar assets and operations, investors should consider such regulations carefully. Although governmental legislation is a matter of public record, the Corporation is unable to predict what additional legislation or amendments governments may enact in the future.

The Corporation's assets and operations are regulated by administrative agencies deriving authority from underlying legislation enacted by the applicable level of government. Regulated aspects of the Corporation's upstream crude oil and natural gas business include all manner of activities associated with the exploration for and production of crude oil and natural gas, including, among other matters: (i) permits for the drilling of wells; (ii) technical drilling and well requirements; (iii) permitted locations and access of operation sites; (iv) operating standards regarding conservation of produced substances and avoidance of waste, such as restricting flaring and venting; (v) minimizing environmental impacts; (vi) storage, injection and disposal of substances associated with production operations; and (vii) the abandonment and reclamation of impacted sites. In order to conduct crude oil and natural gas operations and remain in good standing with the applicable federal or provincial regulatory scheme, producers must comply with applicable legislation, regulations, orders, directives and other directions (all of which are subject to governmental oversight, review and revision, from time to time). Compliance in this regard can be costly and a breach of the same may result in fines or other sanctions. The discussion below outlines certain pertinent conditions and regulations that impact the crude oil and natural gas industry in Western Canada.

Pricing and Marketing in Canada

Crude Oil

Producers of crude oil are entitled to negotiate sales contracts directly with crude oil purchasers. As a result, macroeconomic and microeconomic market forces determine the price of crude oil. Worldwide supply and demand factors are the primary determinant of crude oil prices; however, regional market and transportation issues also influence prices. The specific price depends, in part, on crude oil quality, prices of competing fuels, distance to market, availability of transportation, value of refined products, supply/demand balance and contractual terms of sale.

Natural Gas

Negotiations between buyers and sellers determines the price of natural gas sold in intra-provincial, interprovincial and international trade. The price received by a natural gas producer depends, in part, on the price of competing natural gas supplies and other fuels, natural gas quality, distance to market, availability of transportation, length of contract term, weather conditions, supply/demand balance and other contractual terms. Spot and future prices can also be influenced by supply and demand fundamentals on various trading platforms.

Natural Gas Liquids

The pricing of condensates and other NGLs such as ethane, butane and propane sold in intra-provincial, interprovincial and international trade is determined by negotiation between buyers and sellers. Such prices depend, in part, on the quality of the NGLs, price of competing chemical stock, distance to market, access to downstream transportation, length of contract term, supply/demand balance and other contractual terms.

Exports from Canada

Crude oil, natural gas and NGLs exports from Canada are subject to the *National Energy Board Act* (Canada) (the "**NEB Act**") and the *National Energy Board Act Part VI (Oil and Gas) Regulation* (the "**Part VI Regulation**"). The NEB Act and the Part VI Regulation authorize crude oil, natural gas and NGLs exports under either short-term orders or long-term licences. To obtain a crude oil export licence, a mandatory public hearing with the National Energy Board (the "**NEB**") is required. There is no longer a public hearing requirement for the export of natural gas and NGLs. Instead, the NEB uses a written process that includes a public comment period for impacted persons. Following the comment period, the NEB completes its assessment of the application and either approves or denies the application. For natural gas, the maximum duration of an export licence is 40 years and, for crude oil and other gas substances (e.g. NGLs), the maximum term is 25 years. In addition to NEB approval, all crude oil, natural gas and NGLs licences require the approval of the cabinet of the Canadian federal government ("**Cabinet**").

Orders from the NEB provide a short-term alternative to export licences and may be issued more expediently, since they do not require a public hearing or approval from Cabinet. Orders are issued pursuant to the Part VI Regulation for up to one or two years depending on the substance, with the exception of natural gas (other than NGLs) for which an order may be issued for up to twenty years for quantities not exceeding 30,000 m^3 per day.

As to price, exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts continue to meet certain criteria prescribed by the NEB and the federal government. The Corporation does not directly enter into contracts to export its production outside of Canada.

On February 8, 2018, the Government of Canada introduced Bill C-69, draft legislation that, if enacted, will replace the NEB with the Canadian Energy Regulator ("**CER**"). The CER will take on the NEB's responsibilities with respect to the export of crude oil, natural gas and NGLs from Canada. However, it is not proposed that the legislative regime relating to exports of crude oil, natural gas and NGLs exports from Canada will substantively change under the new regime as currently drafted.

As discussed in more detail below, one major constraint to the export of crude oil, natural gas and NGLs outside of Canada is the deficit of overall pipeline and other transportation capacity to transport production from Western Canada to the United States and other international markets. Although certain pipeline and other transportation projects are underway, many contemplated projects have been cancelled or are delayed due to regulatory hurdles, court challenges and economic and other socio-political factors. The transportation capacity deficit is not likely to be resolved quickly. Major pipeline and other transportation infrastructure projects typically require a significant length of time to complete once all regulatory and other hurdles have been cleared. In addition, production of crude oil, natural gas and NGLs in Canada is expected to continue to increase, which may further exacerbate the transportation capacity deficit.

Transportation Constraints and Market Access

Producers negotiate with pipeline operators (or other transport providers) to transport their products to market on a firm or interruptible basis. Transportation availability is highly variable across different areas and regions. This variability can determine the nature of transportation commitments available, the number of potential customers that can be reached in a cost-effective manner and the price received. Due to growing production and a lack of new and expanded pipeline and rail infrastructure capacity, producers in Western Canada have experienced low commodity pricing relative to other markets in the last several years.

Under the Canadian constitution, interprovincial and international pipelines fall within the federal government's jurisdiction and require a regulatory review and approval by Cabinet. However, recent years have seen a perceived lack of policy and regulatory certainty at a federal level. Although the current federal government introduced Bill C-69 to amend the current federal approval processes, it is uncertain when the new legislation will be brought into force and whether any changes will be made in the interim. It is also uncertain whether any new approval process adopted by the federal government will result in a more efficient approval process. The lack of regulatory certainty is likely to have an influence on investment decisions for major projects. Even when projects are approved on a federal level, such projects often face further delays due to interference by provincial and municipal governments, as well as court challenges related to issues such as indigenous title, the government's duty to consult and accommodate indigenous peoples and the sufficiency of the relevant environmental review processes. Such political and legal opposition creates further uncertainty. In addition, export pipelines from Canada to the United States face additional uncertainty as such pipelines require approvals of several levels of government in the United States.

In the face of this regulatory uncertainty, the Canadian crude oil and natural gas industry has experienced significant difficulty expanding the existing network of transportation infrastructure for crude oil, natural gas and NGLs, including pipelines, rail, trucks and marine transport. Improved access to global markets, especially the Midwest United States and export shipping terminals on the west coast of Canada, could help to alleviate the downward pressures affecting commodity prices. Several proposals have been announced to increase pipeline capacity out of Western Canada to reach Eastern Canada, the United States and international markets via export terminals. While certain projects are proceeding, the regulatory approval process and other economic and socio-political factors related to transportation and export infrastructure has led to the delay, suspension or cancellation of many pipeline projects or their cancellation altogether.

With respect to the current state of the transportation and exportation of crude oil from Western Canada to domestic and international markets, the Enbridge Line 3 Expansion from Hardisty, Alberta, to Superior, Wisconsin, formerly expected to be in-service in late 2019, experienced a construction permitting setback and is now expected to be in-service in the latter half of 2020.

The proposed Trans Mountain Pipeline expansion received Cabinet approval in November 2016. Following a period of sustained political opposition in British Columbia, the federal government entered into an agreement with Kinder Morgan Cochin ULC in May 2018 to purchase the shares and units of the entities that own and operate the Trans Mountain Pipeline system. The shareholders subsequently voted to approve the transaction in August 2018. However, the Trans Mountain Pipeline expansion experienced a setback when, in August 2018, the Federal Court of Appeal identified deficiencies in the NEB's environmental assessment and the Government's indigenous consultations. The Court quashed the accompanying certificate of public convenience and necessity and directed Cabinet to correct these deficiencies. Following the Court's direction, the Cabinet ordered the NEB to reconsider its recommendation in light of the Federal Court of Appeal decision. The NEB is expected to deliver an updated recommendation and list of proposed conditions to Cabinet by February 22, 2019. While the scope of the NEB's reconsideration is limited to the environmental effects of project-related marine shipping, its recommendation will apply to the entire proposed pipeline expansion. Cabinet will have three months to consider the NEB's report and, subject to a new round of indigenous consultation, decide whether it will approve or deny the pipeline expansion.

While it was expected that construction on the Keystone XL Pipeline would commence in the first half of 2019, pre-construction work was halted in late 2018 when a U.S. Federal Court judge determined the underlying environmental review was inadequate. This decision has been appealed.

Finally, Bill C-48 continues to advance through the federal legislative process. If enacted, Bill C-48 will impose a moratorium on tanker traffic transporting certain crude oil and NGLs products from British Columbia's north coast. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Federal*".

On November 28, 2018, the Government of Alberta announced that Alberta has started negotiations for investment in new rail capacity to address the historically high price differential. Commencing in late 2019, the Government of Alberta intends to create enough new rail capacity to move 120,000 barrels a day out of the province. The Government expects that the railcar acquisition will narrow the crude oil price gap by up to $4 per barrel and will provide junior producers with a more affordable option to move their crude oil to market.

Natural gas prices in Alberta and British Columbia have also been constrained in recent years due to increasing North American supply, limited access to markets and limited storage capacity. While companies that secure firm access to transport their natural gas production out of Western Canada may be able to access more markets and obtain better pricing, other companies may be forced to accept spot pricing in Western Canada for their natural gas, which in the last several years has generally been depressed (at times producers have received negative pricing for their natural gas production). Required repairs or upgrades to existing pipeline systems have also led to further reduced capacity and apportionment of firm access, which in Western Canada may be further exacerbated by natural gas storage limitations. Additionally, while a number of liquefied natural gas export plants have been proposed for the west coast of Canada, government decision-making, regulatory uncertainty, opposition from environmental and indigenous groups, and changing market conditions, have resulted in the cancellation or delay of many of these projects. In October 2018, the proponents of the LNG Canada liquefied natural gas export terminal announced a positive final investment decision to proceed with the project.

Curtailment

On December 2, 2018, the Government of Alberta announced that, commencing January 1, 2019, it would mandate a short-term reduction in provincial crude oil and crude bitumen production. As contemplated in the *Curtailment Rules* (Alberta), the Government of Alberta will, on a monthly basis, direct crude oil producers producing more than 10,000 bbls/d to curtail their production according to a pre-determined formula that apportions production limits proportionately amongst those operators subject to a curtailment order. The first curtailment order took effect on January 1, 2019, limiting province-wide production of crude oil and crude bitumen to 3.56 million bbls/d—a reduction of approximately 8.7% of total daily average crude oil production in Alberta during December 2018. The Government of Alberta indicated that it expected the curtailment rate to gradually drop over the course of 2019. As a result of decreasing price differentials and volumes of crude oil and crude bitumen in storage, the Government of Alberta announced on January 30, 2019, that it would ease the mandatory production curtailment beginning February 1, 2019, increasing the allowable production cap by 75,000 bbls/d to a maximum output of approximately 3.63 million bbls/d. The Corporation is not subject to a curtailment order.

The North American Free Trade Agreement and Other Trade Agreements

The North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, the United States and Mexico came into force on January 1, 1994. Under the terms of NAFTA's Article 605, a proportionality clause prevents Canada from implementing policies that limit exports to the United States and Mexico, relative to the total supply produced in Canada. Canada remains free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to the total supply of goods of Canada as compared to the proportion prevailing in the most recent 36 month period; (ii) impose an export price higher than the domestic price (subject to an exception with respect to certain measures which only restrict the volume of exports); and (iii) disrupt normal channels of supply. Further, all three signatory countries are prohibited from imposing a minimum or maximum price requirement on exports (where any other form of quantitative restriction is prohibited) and imports (except as permitted in the enforcement of countervailing and anti-dumping orders and undertakings). NAFTA also requires energy regulators to ensure the orderly and equitable implementation of any regulatory changes and to ensure that the application of such changes will cause minimal disruption to contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements.

On November 30, 2018, U.S. President Donald Trump, Prime Minister Trudeau, and outgoing Mexican President Enrique Pena Nieto signed an authorization for a new trade deal that will replace NAFTA, referred to as the United States-Mexico-Canada Agreement ("**USMCA**"). However, NAFTA remains the North American trade agreement currently in force until the legislative bodies of the three signatory countries ratify the USMCA. Amid political uncertainty in Canada, Mexico, and the United States it is unclear when the end of the NAFTA era will be. As the United States remains by far Canada's largest trade partner and the largest international market for the export of crude oil, natural gas and NGLs from Canada the implementation of the final version ratified version of the USMCA could have an impact on Western Canada's crude oil and natural gas industry at large, including the Corporation's business.

As discussed above, at the end of 2018 the Government of Alberta announced curtailment of Alberta's crude oil and bitumen production for 2019. Curtailment complies with NAFTA's Article 605, under which Canada must make available a consistent proportion of the crude oil and bitumen produced to the other NAFTA signatories. As a result of the proportionality rule, reducing Canadian supply reduced the required offering under NAFTA, with the result that the amount of crude oil and bitumen that Canada is required to offer, which Canadian crude oil is at depressed prices, may be reduced. It is not clear whether the USMCA will come into force before the Government of Alberta's curtailment order is repealed automatically on December 31, 2019.

The USMCA does not contain the proportionality rules of NAFTA's Article 605. The elimination of the proportionality clause removes a barrier in Canada's transition to a more diversified export portfolio. While diversification depends on the construction of infrastructure allowing more Canadian production to reach Eastern Canada, Asia, and Europe, the USMCA may allow for greater export diversification than currently exists under NAFTA.

Canada has also pursued a number of other international free trade agreements with other countries around the world. As a result, a number of free trade or similar agreements are in force between Canada and certain other countries while in other circumstances Canada has been unsuccessful in its efforts. Canada and the European Union recently agreed to the Comprehensive Economic and Trade Agreement ("**CETA**"), which provides for duty-free, quota-free market access for Canadian crude oil and natural gas products to the European Union. Although CETA remains subject to ratification by certain national legislatures in the European Union, provisional application of CETA commenced on September 21, 2017. In addition, Canada and ten other countries recently concluded discussions and agreed on the draft text of the Comprehensive and Progressive Agreement for Trans-Pacific Partnership ("**CPTPP**"), which is intended to allow for preferential market access among the countries that are parties to the CPTPP. On December 30, 2018 the CPTPP came into force among the first six countries to ratify the agreement – Canada, Australia, Japan, Mexico, New Zealand, and Singapore. While it is uncertain what effect CETA, CPTPP or any other trade agreements will have on the crude oil and natural gas industry in Canada, the lack of available infrastructure for the offshore export of crude oil and natural gas may limit the ability of Canadian crude oil and natural gas producers to benefit from such trade agreements.

Land Tenure

The respective provincial governments (i.e. the Crown), predominantly own the mineral rights to crude oil and natural gas located in Western Canada, with the exception of Manitoba (which only owns 20% of the mineral rights). Provincial governments grant rights to explore for and produce crude oil and natural gas pursuant to leases, licences and permits for varying terms, and on conditions set forth in provincial legislation, including requirements to perform specific work or make payments. The provincial governments in Western Canada's provinces conduct regular land sales where crude oil and natural gas companies bid for leases to explore for and produce crude oil and natural gas pursuant to mineral rights owned by the respective provincial governments. The leases generally have a fixed term; however, a lease may generally be continued after the initial term where certain minimum thresholds of production have been reached, all lease rental payments have been paid on time and other conditions are satisfied.

To develop crude oil and natural gas resources, it is necessary for the mineral estate owner to have access to the surface lands as well. Each province has developed its own process for obtaining surface access to conduct operations that operators must follow throughout the lifespan of a well, including notification requirements and providing compensation for affected persons for lost land use and surface damage.

Each of the provinces of Alberta and British Columbia have implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a lease or licence. Additionally, the provinces of Alberta and British Columbia have shallow rights reversion for shallow, non-productive geological formations for new leases and licences.

In addition to Crown ownership of the rights to crude oil and natural gas, private ownership of crude oil and natural gas (i.e. freehold mineral lands) also exists in the provinces of Alberta and British Columbia. In each of the provinces of Alberta and British Columbia approximately 19% and 6%, respectively, of the mineral rights are owned by private freehold owners. Rights to explore for and produce such crude oil and natural gas are granted by a lease or other contract on such terms and conditions as may be negotiated between the owner of such mineral rights and crude oil and natural gas explorers and producers.

An additional category of mineral rights ownership includes ownership by the Canadian federal government of some legacy mineral lands and within indigenous reservations designated under the *Indian Act* (Canada). Indian Oil and Gas Canada ("**IOGC**"), which is a federal government agency, manages subsurface and surface leases, in consultation with the applicable indigenous peoples, for exploration and production of crude oil and natural gas on indigenous reservations.

Royalties and Incentives

General

Each province has legislation and regulations that govern royalties, production rates and other matters. The royalty regime in a given province is a significant factor in the profitability of oil sands projects and crude oil, natural gas and NGLs production. Royalties payable on production from lands where the Crown does not hold the mineral rights are determined by negotiation between the mineral freehold owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Royalties from production on Crown lands are determined by governmental regulation and are generally calculated as a percentage of the value of gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery and the type or quality of the petroleum substance produced.

Occasionally the governments of Western Canada's provinces create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays or royalty tax credits and are often introduced when commodity prices are low to encourage exploration and development activity. In addition, such programs may be introduced to encourage producers to undertake initiatives using new technologies that may enhance or improve recovery of crude oil, natural gas and NGLs.

In addition, the federal government may from time to time provide incentives to the oil and gas industry. In November of 2018, the federal government announced its plans to implement an accelerated investment incentive, which will provide oil and gas businesses with eligible Canadian development expenses and Canadian oil and gas property expenses with a first year deduction of one and a half times the deduction that is otherwise available. The federal government also announced in late 2018 that it will make $1.6 billion available to the oil and natural gas industry in light of worsening commodity price differentials. The aid package, however, is mostly in the form of loans and is earmarked for crude oil and natural gas projects related to economic diversification as well as direct funding for clean growth crude oil and natural gas projects.

Producers and working interest owners of crude oil and natural gas rights may also carve out additional royalties or royalty-like interests through non-public transactions, which include the creation of instruments such as overriding royalties, net profits interests and net carried interests.

Alberta

In Alberta, the provincial government royalty rates apply to Crown-owned mineral rights. In 2016, Alberta adopted a modernized Alberta royalty framework (the "**Modernized Framework**") that applies to all wells drilled after December 31, 2016. The previous royalty framework (the "**Old Framework**") will continue to apply to wells drilled prior to January 1, 2017 for a period of ten years ending on December 31, 2026. After the expiry of this ten-year period, these older wells will become subject to the Modernized Framework.

The Modernized Framework applies to all hydrocarbons other than oil sands which will remain subject to their existing royalty regime. Royalties on production from non-oil sands wells under the Modernized Framework are determined on a "revenue-minus-costs" basis with the cost component based on a Drilling and Completion Cost Allowance formula for each well, depending on its vertical depth and/or horizontal length. The formula is based on the industry's average drilling and completion costs as determined by the Alberta Energy Regulator (the "**AER**") on an annual basis.

Producers pay a flat royalty rate of 5% of gross revenue from each well that is subject to the Modernized Framework until the well reaches payout. Payout for a well is the point at which cumulative gross revenues from the well equals the Drilling and Completion Cost Allowance for the well set by the AER. After payout, producers pay an increased post-payout royalty on revenues of between 5% and 40% for crude oil and pentanes and 5% and 36% for methane, ethane, propane and butane, all determined by reference to the then current commodity prices of the various hydrocarbons. Similar to the Old Framework, the post-payout royalty rate under the Modernized Framework varies with commodity prices. Once production in a mature well drops below a threshold level where the rate of production is too low to sustain the full royalty burden, its royalty rate is adjusted downward towards a minimum of 5% as the mature well's production declines. As the Modernized Framework uses deemed drilling and completion costs in calculating the royalty and not the actual drilling and completion costs incurred by a producer, low cost producers benefit if their well costs are lower than the Drilling and Completion Cost Allowance and, accordingly, they continue to pay the lower 5% royalty rate for a period of time after their wells achieve actual payout.

The Old Framework is applicable to all conventional crude oil and natural gas wells drilled prior to January 1, 2017 and bitumen production. Subject to certain available incentives, effective from the January 2011 production month, royalty rates for conventional crude oil production under the Old Framework range from a base rate of 0% to a cap of 40%. Subject to certain available incentives, effective from the January 2011 production month, royalty rates for natural gas production under the Old Framework range from a base rate of 5% to a cap of 36%. The Old Framework also includes a natural gas royalty formula which provides for a reduction based on the measured depth of the well below 2,000 metres deep, as well as the acid gas content of the produced gas. Under the Old Framework, the royalty rate applicable to NGLs is a flat rate of 40% for pentanes and 30% for butanes and propane. Currently, producers of crude oil and natural gas from Crown lands in Alberta are required to pay annual rental payments, at a rate of $3.50 per hectare, and make monthly royalty payments in respect of crude oil and natural gas produced.

The Government of Alberta has from time to time implemented drilling credits, incentives or transitional royalty programs to encourage crude oil and natural gas development and new drilling. In addition, the Government of Alberta has implemented certain initiatives intended to accelerate technological development and facilitate the development of unconventional resources, including as applied to coalbed methane wells, shale gas wells and horizontal crude oil and natural gas wells.

Freehold mineral taxes are levied for production from freehold mineral lands on an annual basis on calendar year production. Freehold mineral taxes are calculated using a tax formula that takes into consideration, among other things, the amount of production, the hours of production, the value of each unit of production, the tax rate and the percentages that the owners hold in the title. On average, in Alberta the tax levied is 4% of revenues reported from freehold mineral title properties. The freehold mineral taxes would be in addition to any royalty or other payment paid to the owner of such freehold mineral rights, which are established through private negotiation.

British Columbia

Producers of crude oil in British Columbia receive royalty invoices each month for every well or unitized tract that is producing and/or reporting sales. The royalty calculation takes into account the production of crude oil on a well-by-well basis, which can be up to 40%, based on factors such as the volume of crude oil produced by the well or tract and the crude oil vintage, which depends on density of the substance and when the crude oil pool was located. Royalty rates are reduced on low-productivity wells and other wells with applicable royalty exemptions to reflect higher per-unit costs of exploration and extraction.

Producers of natural gas and NGLs in British Columbia receive royalty invoices each month for every well or unitized tract that is producing and/or reporting sales. Different royalty rates apply for natural gas, NGLs and natural gas by-products. For natural gas, the royalty rate can be up to 27% of the value of the natural gas and is based on whether the gas is classified as conservation gas or non-conservation gas, as well as reference prices and the select price. For NGLs and condensates, the royalty rate is fixed at 20%.

The royalties payable by each producer will thus vary depending on the types of wells and the characteristics of the substances being produced. Additionally, the Government of British Columbia maintains a number of targeted royalty programs for key resource areas intended to increase the competitiveness of British Columbia's low productivity natural gas wells. These include both royalty credit and royalty reduction programs.

Producers of crude oil and natural gas from freehold lands in British Columbia are required to pay monthly freehold production taxes. For crude oil, the applicable freehold production tax is based on the volume of monthly production, which is either a flat rate, or, beyond a certain production level, is determined using a sliding scale formula based on the production level. For natural gas, the applicable freehold production tax is a flat rate, or, at certain production levels, is determined using a sliding scale formula based on a reference price, and depends on whether the natural gas is conservation gas or non-conservation gas. The production tax rate for freehold NGLs is a flat rate of 12.25%. Additionally, owners of mineral rights in British Columbia must pay an annual mineral land tax that is equivalent to $4.94 per hectare of producing lands. Non-producing lands are taxed on a sliding scale from $1.25 to $4.94 per hectare, depending on the total number of hectares owned by the entity.

Freehold and Other Types of Non-Crown Royalties

Royalties on production from privately-owned freehold lands are negotiated between the mineral freehold owner and the lessee under a negotiated lease or other contract. Producers and working interest participants may also pay additional royalties to parties other than the mineral freehold owner where such royalties are negotiated through private transactions.

In addition to the royalties payable to the mineral owners (or to other royalty holders if applicable), producers of crude oil and natural gas from freehold lands in each of the Western Canadian provinces are required to pay freehold mineral taxes or production taxes. Freehold mineral taxes or production taxes are taxes levied by a provincial government on crude oil and natural gas production from lands where the Crown does not hold the mineral rights. A description of the freehold mineral taxes payable in each of the Western Canadian provinces is included in the above descriptions of the royalty regimes in such provinces.

IOGC is a special agency responsible for managing and regulating the crude oil and natural gas resources located on indigenous reservations across Canada. IOGC's responsibilities include negotiating and issuing the crude oil and natural gas agreements between indigenous groups and crude oil and natural gas companies, as well as collecting royalty revenues on behalf of indigenous groups and depositing the revenues in their trust accounts. While certain standards exist, the exact terms and conditions of each crude oil and natural gas lease dictate the calculation of royalties owed, which may vary depending on the involvement of the specific indigenous group. Ultimately, the relevant indigenous group must approve the terms.

Regulatory Authorities and Environmental Regulation

General

The Canadian crude oil and natural gas industry is currently subject to environmental regulation under a variety of Canadian federal, provincial, territorial and municipal laws and regulations, all of which are subject to governmental review and revision from time to time. Such regulations provide for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with certain crude oil and natural gas industry operations, such as sulphur dioxide and nitrous oxide. The regulatory regimes set out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well, facility and pipeline sites. Compliance with such regulations can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licences and authorizations, civil liability and the imposition of material fines and penalties. In addition to these specific, known requirements, future changes to environmental legislation, including anticipated legislation for air pollution and greenhouse gas ("**GHG**") emissions, may impose further requirements on operators and other companies in the crude oil and natural gas industry.

Federal

Canadian environmental regulation is the responsibility of both the federal and provincial governments. Where there is a direct conflict between federal and provincial environmental legislation in relation to the same matter, the federal law will prevail. However, such conflicts are uncommon. The federal government has primary jurisdiction over federal works, undertakings and federally regulated industries such as railways, aviation and interprovincial transport including interprovincial pipelines.

On June 20, 2016, the federal government launched a review of current environmental and regulatory processes. On February 8, 2018, the Government of Canada introduced draft legislation to overhaul the existing environmental assessment process and replace the NEB with the CER. Pursuant to the draft legislation, the Impact Assessment Agency of Canada (the "**Agency**") would replace the Canadian Environmental Assessment Agency. It appears that additional categories of projects may be included within the new impact assessment process, such as large-scale wind power facilities and in-situ oilsands facilities. The revamped approval process for applicable major developments will have specific legislated timelines at each stage of the formal impact assessment process. The Agency's process would focus on: (i) early engagement by proponents to engage the Agency and all stakeholders such as the