BIRCHCLIFF ENERGY LTD.

Year Ended December 31, 2018

ANNUAL INFORMATION FORM

March 13, 2019

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GLOSSARY OF TERMS

In this Annual Information Form, the capitalized terms set forth below have the following meanings:

"**2016 Private Placement**" means the private placement by the Corporation of an aggregate of 3,000,000 Subscription Receipts to The Schulich Foundation at a price of $6.25 per Subscription Receipt for aggregate gross proceeds of $18,750,000, which closed on July 13, 2016.

"**2016 Public Offering**" means the bought deal offering by way of short form prospectus of an aggregate of 107,520,000 Subscription Receipts at a price of $6.25 per Subscription Receipt for aggregate gross proceeds of $672,000,000, which closed on July 13, 2016.

"**2017 Resource Assessment**" has the meaning set forth in Appendix A.

"**2018 Resource Assessment**" has the meaning set forth in Appendix A.

"**2019 Capital Program**" has the meaning set forth under the heading *"General Development of the Business – Recent Developments".*

"**ABCA**" means the *Business Corporations Act* (Alberta).

"**AB LFP Program**" has the meaning set forth under the heading *"Industry Conditions – Regulatory Authorities and Environmental Regulation – Alberta – Liability Management Rating Program"*.

"**AB LLR Program**" has the meaning set forth under the heading *"Industry Conditions – Regulatory Authorities and Environmental Regulation – Alberta – Liability Management Rating Program"*.

"**AB LMR Program**" has the meaning set forth under the heading *"Industry Conditions – Regulatory Authorities and Environmental Regulation – Alberta – Liability Management Rating Program"*.

"**AB OWL Program**" has the meaning set forth under the heading *"Industry Conditions – Regulatory Authorities and Environmental Regulation – Alberta – Liability Management Rating Program"*.

"**AER**" means the Alberta Energy Regulator.

"**AltaGas**" means AltaGas Ltd.

"**Annual Information Form**" means this annual information form of the Corporation dated March 13, 2019 for the year ended December 31, 2018.

"**BIA**" means the *Bankruptcy and Insolvency Act* (Canada).

"**Bill C-48**" has the meaning set forth under the heading *"Industry Conditions – Transportation Constraints and Market Access".*

"**Bill C-69**" has the meaning set forth under the heading *"Industry Conditions – Exports from Canada".*

"**Birchcliff**" or the "**Corporation**" means Birchcliff Energy Ltd.

"**Board**" means the board of directors of the Corporation.

"**Cabinet**" has the meaning set forth under the heading *"Industry Conditions – Exports from Canada".*

"**CCIR**" means the *Carbon Competitiveness Incentive Regulation* (Alberta).

"**CER**" has the meaning set forth under the heading *"Industry Conditions – Exports from Canada".*

"**CETA**" has the meaning set forth under the heading *"Industry Conditions – NAFTA and Other Trade Agreements".*

"**Charlie Lake Light Oil Resource Play**" has the meaning set forth under the heading *"General Development of the Business – Three Year History – 2017".*

"**CLA**" means the *Climate Leadership Act* (Alberta).

"**CLP**" has the meaning set forth under the heading *"Industry Conditions – Climate Change Regulation – Alberta".*

"**COGE Handbook**" means the Canadian Oil and Gas Evaluation Handbook maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter), as amended from time to time.

"**Common Shares**" means the common shares of the Corporation.

"**Consolidated Reserves Report**" has the meaning set forth under the heading *"Statement of Reserves Data and Other Oil and Gas Information – Disclosure of Reserves Data"*.

"**COR**" means a certificate of recognition.

"**CPTPP**" has the meaning set forth under the heading *"Industry Conditions – NAFTA and Other Trade Agreements".*

"**CRA**" means the Canada Revenue Agency.

"**Credit Facilities**" has the meaning set forth under the heading *"Description of Capital Structure – Credit Facilities"*.

"**CSA Staff Notice 51-324**" means the Canadian Securities Administrators' Staff Notice 51-324 – *Revised Glossary to NI 51-101 Standards of Disclosure for Oil and Gas Activities*.

"**Current Market Price**" has the meaning set forth under the heading *"Description of Capital Structure – Authorized Share Capital and Securities Outstanding – Preferred Shares – Series C Preferred Shares"*.

"**Deloitte**" means Deloitte LLP, independent qualified reserves evaluators of Calgary, Alberta.

"**Deloitte Price Forecast**" means Deloitte's December 31, 2018 forecast price and cost assumptions set out under the heading *"Statement of Reserves Data and Other Oil and Gas Information – Pricing Assumptions – Forecast Prices Used in Estimates".*

"**Deloitte Reserves Report**" has the meaning set forth under the heading *"Statement of Reserves Data and Other Oil and Gas Information – Disclosure of Reserves Data"*.

"**Directive 013**" means Directive 013: *Suspension Requirements for Wells* published by the AER.

"**Directive 067**" means Directive 067: *Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals* published by the AER.

"**EPCs**" has the meaning set forth under the heading *"Industry Conditions – Climate Change Regulation – Alberta".*

"**ESTMA**" means the *Extractive Sector Transparency Measures Act* (Canada).

"**FCA**" has the meaning set forth under the heading *"Legal Proceedings and Regulatory Actions"*.

"**Federal Government**" means the federal Government of Canada.

"**Federal Methane Regulations**" has the meaning set forth under the heading *"Industry Conditions – Climate Change Regulation – Federal".*

"**GHG**" means greenhouse gas.

"**Gordondale Acquisition**" means the acquisition by the Corporation of certain petroleum and natural gas properties, interests and related assets primarily located in the Gordondale area pursuant to the Gordondale Acquisition Agreement, which acquisition closed on July 28, 2016.

"**Gordondale Acquisition Agreement**" means the asset sale agreement dated June 21, 2016 between the Corporation, Encana Corporation and a wholly-owned subsidiary of Encana Corporation, as amended, providing for the Gordondale Acquisition.

"**Gordondale Gas Plant**" means the deep-cut sour gas processing facility in Gordondale which is owned and operated by AltaGas.

"**Gordondale Processing Arrangement**" has the meaning set forth under the heading *"General Development of the Business – Three Year History – 2018".*

"**IAA**" has the meaning set forth under the heading *"Industry Conditions – Regulatory Authorities and Environmental Regulation – Federal".*

"**IOGC**" has the meaning set forth under the heading *"Industry Conditions – Land Tenure".*

"**IWCP**" has the meaning set forth under the heading *"Industry Conditions – Regulatory Authorities and Environmental Regulation – Alberta – Liability Management Rating Program"*.

"**LMR**" has the meaning set forth under the heading *"Industry Conditions – Regulatory Authorities and Environmental Regulation – Alberta – Liability Management Rating Program"*.

"**McDaniel**" means McDaniel & Associates Consultants Ltd., independent qualified reserves evaluators of Calgary, Alberta.

"**McDaniel Reserves Report**" has the meaning set forth under the heading *"Statement of Reserves Data and Other Oil and Gas Information – Disclosure of Reserves Data"*.

"**Modernized Framework**" has the meaning set forth under the heading *"Industry Conditions – Royalties and Incentives – The Royalty Framework in Alberta – Crown Royalties"*.

"**Montney/Doig Resource Play**" means Birchcliff's Montney and Doig formations resource play located northwest of Grande Prairie, Alberta.

"**NAFTA**" means the North American Free Trade Agreement between the Governments of Canada, the United States and Mexico.

"**NEB**" means the National Energy Board.

"**NEB Act**" means the *National Energy Board Act* (Canada).

"**NGTL System**" means the pipeline system owned by Nova Gas Transmission Ltd., a subsidiary of TransCanada.

"**NI 51-101**" means National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities*.

"**NI 51-102**" means National Instrument 51-102 – *Continuous Disclosure Obligations*.

"**NI 52-110**" means National Instrument 52-110 – *Audit Committees*.

"**NIT**" means Alberta Nova Inventory Transfer.

"**OBA**" has the meaning set forth under the heading *"Industry Conditions – Climate Change Regulation – Alberta".*

"**OGCA**" means the *Oil and Gas Conservation Act* (Alberta).

"**OPEC**" means the Organization of the Petroleum Exporting Countries.

"**Options**" means stock options to purchase Common Shares.

"**Order**" has the meaning set forth under the heading "*Directors and Officers – Cease Trade Orders, Bankruptcies, Penalties or Sanctions".*

"**Orphan Fund**" has the meaning set forth under the heading *"Industry Conditions – Regulatory Authorities and Environmental Regulation – Alberta – Liability Management Rating Program"*.

"**Pan-Canadian Framework**" has the meaning set forth under the heading *"Industry Conditions – Climate Change Regulation – Federal".*

"**Part VI Regulations**" means the *National Energy Board Act Part VI (Oil and Gas) Regulations*.

"**Pembina Facility**" has the meaning set forth under the heading *"Description of the Business – Principal Properties – The Montney/Doig Resource Play – Key Operating Areas – Gordondale"*.

"**Performance Warrants**" means the performance warrants of the Corporation which expire on January 31, 2020, with each performance warrant providing the right to purchase one Common Share at a price of $3.00 per Common Share.

"**Pouce Coupe Acquisition**" means the acquisition by the Corporation of certain petroleum and natural gas properties, interests and related assets located in the Pouce Coupe area pursuant to a purchase and sale agreement dated November 2, 2018, which acquisition closed on January 3, 2019.

"**Pouce Coupe Gas Plant**" means Birchcliff's 100% owned and operated natural gas processing plant located in the Pouce Coupe area of Alberta.

"**Preferred Shares**" means the preferred shares of the Corporation as a class.

"**Previous Framework**" has the meaning set forth under the heading *"Industry Conditions – Royalties and Incentives – The Royalty Framework in Alberta – Crown Royalties".*

"**Prior Consolidated Reserves Report**" means the consolidated reserves report prepared by Deloitte with an effective date of December 31, 2017.

"**Progress Disposition**" means the disposition by the Corporation of certain petroleum and natural gas properties, interests and related assets primarily located in the Progress area on the Charlie Lake Light Oil Resource Play pursuant to a purchase and sale agreement dated August 10, 2017, which disposition closed on October 2, 2017.

"**Reassessment**" has the meaning set forth under the heading *"Legal Proceedings and Regulatory Actions"*.

"**Redwater**" has the meaning set forth under the heading *"Industry Conditions – Regulatory Authorities and Environmental Regulation – Alberta – Liability Management Rating Program"*.

"**SEDAR**" means the System for Electronic Document Analysis and Retrieval.

"**Series A Preferred Shares**" means the cumulative redeemable preferred shares, Series A of the Corporation which were issued on August 8, 2012.

"**Series B Preferred Shares**" means the cumulative redeemable preferred shares, Series B of the Corporation which are issuable on the conversion of the Series A Preferred Shares.

"**Series C Preferred Shares**" means the cumulative redeemable preferred shares, Series C of the Corporation which were issued on June 14, 2013.

"**SGER**" has the meaning set forth under the heading *"Industry Conditions – Climate Change Regulation – Alberta".*

"**Stock Option Plan**" means the Corporation's stock option plan, as amended and restated on December 13, 2018.

"**Subscription Receipts**" means the 110,520,000 subscription receipts of the Corporation which were issued on July 13, 2016 pursuant to the 2016 Public Offering and the 2016 Private Placement.

"**Syndicated Credit Facility**" has the meaning set forth under the heading *"Description of Capital Structure – Credit Facilities*".

"**TCC**" has the meaning set forth under the heading *"Legal Proceedings and Regulatory Actions"*.

"**TCC Decision**" has the meaning set forth under the heading *"Legal Proceedings and Regulatory Actions"*.

"**TCPL**" means TransCanada PipeLines Limited.

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

"**UNFCCC**" has the meaning set forth under the heading *"Industry Conditions – Climate Change Regulation – Federal"*.

"**USMCA**" has the meaning set forth under the heading *"Industry Conditions – NAFTA and Other Trade Agreements".*

"**Veracel**" means Veracel Inc.

"**Western Canadian Sedimentary Basin**" means the vast sedimentary basin underlying Western Canada that is the source of most of Western Canada's current oil and natural gas production.

"**Working Capital Facility**" has the meaning set forth under the heading *"Description of Capital Structure – Credit Facilities*".

"**working interest**" means a percentage of ownership in an oil and natural gas property, obligating the owner to share in the costs of exploration, development and operations and granting the owner the right to share in production revenues after royalties are paid.

"**Worsley Disposition**" means the disposition by the Corporation of certain petroleum and natural gas properties, interests and related assets primarily located in the Worsley area on the Charlie Lake Light Oil Resource Play pursuant to a purchase and sale agreement dated August 1, 2017, which disposition closed on August 31, 2017.

ABBREVIATIONS AND CONVERSIONS

Abbreviations

The abbreviations set forth below have the following meanings:

Oil and Natural Gas Liquids

bbl	barrel
bbls	barrels
bbls/d	barrels per day
C3+	propane plus
Mbbls	thousand barrels
MMbbls	million barrels
MMbbls/d	million barrels per day
NGLs	natural gas liquids

Natural Gas

Bcf	billion cubic feet
GJ	gigajoule
GJ/d	gigajoules per day
LNG	liquefied natural gas
Mcf	thousand cubic feet
Mcf/d	thousand cubic feet per day
MMBtu	million British thermal units
MMcf	million cubic feet
MMcf/d	million cubic feet per day

Other

AECO	benchmark price for natural gas determined at the AECO 'C' hub in southeast Alberta
Bcfe	billion cubic feet of gas equivalent
boe	barrel of oil equivalent
boe/d	barrel of oil equivalent per day
CO_2e	carbon dioxide equivalent
km	kilometres
Mboe	thousand barrels of oil equivalent
Mcfe	thousand cubic feet of gas equivalent
M$	thousands of dollars
MM$	millions of dollars
NPV	net present value of future net revenue
NYMEX	New York Mercantile Exchange
PIIP	petroleum initially-in-place
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma, for crude oil of standard grade

Conversions

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

From	To	Multiply By
Mcf	cubic metres	28.317
cubic metres	cubic feet	35.315
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

CONVENTIONS

Certain terms used herein are defined in NI 51-101, CSA Staff Notice 51-324 or the COGE Handbook and, unless the context otherwise requires, shall have the same meanings in this Annual Information Form as in NI 51-101, CSA Staff Notice 51-324 or the COGE Handbook, as the case may be.

Unless otherwise indicated, all information contained herein is given at or for the year ended December 31, 2018. Unless otherwise indicated, all dollar amounts are expressed in Canadian dollars and all references to "$", "CDN$" or "dollars" are to Canadian dollars and all references to "US$" are to United States dollars. All financial information contained in this Annual Information Form has been presented in accordance with Canadian generally accepted accounting principles, which are currently International Financial Reporting Standards as issued by the International Accounting Standards Board. Words importing the singular number only include the plural, and vice versa, and words importing any gender include all genders.

PRESENTATION OF OIL AND GAS RESERVES AND RESOURCES

Deloitte prepared the Consolidated Reserves Report, the Deloitte Reserves Report, the Prior Consolidated Reserves Report, the 2018 Resource Assessment and the 2017 Resource Assessment. McDaniel prepared the McDaniel Reserves Report. Such evaluations were prepared in accordance with the standards contained in NI 51-101 and the COGE Handbook that were in effect at the relevant time.

With respect to any disclosure of reserves contained herein relating to portions of Birchcliff's properties, the estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation. Estimates of future net revenue, whether calculated without discount or using a discount rate, do not represent fair market value.

With respect to the discovered resources (including contingent resources) disclosed in this Annual Information Form, there is uncertainty that it will be commercially viable to produce any portion of the resources. With respect to the undiscovered resources (including prospective resources) disclosed in this Annual Information Form, there is no certainty that any portion of the resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources.

Unless otherwise indicated, all volumes of Birchcliff's reserves and resources presented herein are on a gross basis and all volumes of Birchcliff's resources presented herein are on an unrisked basis, meaning that they have not been adjusted for the chance of commerciality.

Reserves Categories

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on the analysis of drilling, geological, geophysical and engineering data; the use of established technology; and specified economic conditions, which are generally accepted as being reasonable.

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

- "**Proved reserves**" are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.
- "**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.
- "**Possible reserves**" are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.

Levels of Certainty for Reported Reserves

The qualitative certainty levels referred to in the definitions above are applicable to "individual reserves 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 estimates are presented. Reported reserves should target the following levels of certainty under a specific set of economic conditions:

- at least a 90% probability that the quantities actually recovered will equal or exceed the estimated proved reserves;
- at least a 50% probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves; and
- at least a 10% probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable plus possible reserves.

A quantitative 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 are 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.

Development and Production Status of Reserves

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

- "**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 (e.g., 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.
    - "**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.

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

- “**Undeveloped reserves**” are those reserves expected to be recovered from known accumulations where a significant expenditure (e.g., when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves category (proved, probable, possible) 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.

Resources and Production

Resources encompass all petroleum quantities that originally existed on or within the earth’s crust in naturally occurring accumulations, including discovered and undiscovered (recoverable and unrecoverable) plus quantities already produced. Resources are classified as follows:

- Total PIIP is that quantity of petroleum that is estimated to exist originally in naturally occurring accumulations. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations, prior to production, plus those estimated quantities in accumulations yet to be discovered. “Total resources” is equivalent to “total PIIP”.

- Discovered PIIP is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production. The recoverable portion of discovered PIIP includes production, reserves and contingent resources; the remainder is unrecoverable.

- Contingent resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies.

- Undiscovered PIIP is that quantity of petroleum that is estimated, on a given date, to be contained in accumulations yet to be discovered. The recoverable portion of undiscovered PIIP is referred to as prospective resources; the remainder is unrecoverable.

- Prospective resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects.

- Unrecoverable is that portion of discovered and undiscovered PIIP quantities which is estimated, as of a given date, not to be recoverable by future development projects. A portion of these quantities may become recoverable in the future as commercial circumstances change or technological developments occur; the remaining portion may never be recovered due to the physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

- Production is the cumulative quantity of petroleum that has been recovered at a given date.

Uncertainty Ranges for Resources

Estimates of resource volumes can be categorized according to the range of uncertainty associated with the estimates. Uncertainty ranges are described in the COGE Handbook as low, best and high estimates as follows:

- A “low estimate” (1C) is considered to be a conservative estimate of the quantity that will actually be recovered. It is likely that the actual remaining quantities recovered will exceed the low estimate. If probabilistic methods are used, there should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the low estimate.

- A "best estimate" (2C) is considered to be the best estimate of the quantity that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. If probabilistic methods are used, there should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate.

- A "high estimate" (3C) is considered to be an optimistic estimate of the quantity that will actually be recovered. It is unlikely that the actual remaining quantities recovered will exceed the high estimate. If probabilistic methods are used, there should be at least a 10% probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

Interest in Reserves, Resources, Production, Wells and Properties

"**Gross**" means:

(a) in relation to Birchcliff's interest in production, reserves or resources, Birchcliff's working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests of Birchcliff;

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

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

"**Net**" means:

(a) in relation to Birchcliff's interest in production, reserves or resources, Birchcliff's working interest (operating or non-operating) share after deduction of royalty obligations, plus Birchcliff's royalty interests in production or reserves;

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

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

Forecast Prices and Costs

"**Forecast prices and costs**" means future prices and costs that are:

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

(b) if, and only to the extent that, there are fixed or presently determinable future prices or costs to which Birchcliff 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).

SPECIAL NOTES TO READER

Boe and Bcfe Conversions

Boe amounts have been calculated by using the conversion ratio of 6 Mcf of natural gas to 1 bbl of oil and Bcfe amounts have been calculated by using the conversion ratio of 1 bbl of oil to 6 Mcf of natural gas. Boe and Bcfe amounts may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf to 1 bbl and a Bcfe conversion ratio of 1 bbl to 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 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

Resource (Drilling) Locations

This Annual Information Form discloses a total of 2,003 contingent development pending resource locations on the Montney/Doig Resource Play as disclosed in Appendix A to this Annual Information Form, which represent the number of wells forecast to be drilled under the development plans for Birchcliff's contingent resource development pending projects. None of these locations have any reserves attributed to them in the Consolidated Reserves Report. These locations were estimated by Deloitte based on Birchcliff's prospective (i.e. potential) acreage and an assumption as to the number of wells that can be drilled per section based on industry practice and an evaluation of applicable geologic, seismic, engineering, production and reserves information. Birchcliff's ability to drill and develop these locations and the drilling locations on which Birchcliff actually drills wells depends on a number of uncertainties and factors, including, but not limited to, the availability of capital, equipment and personnel, oil and natural gas prices, costs, inclement weather, seasonal restrictions, drilling results, additional geological, geophysical and reservoir information that is obtained, production rate recovery, gathering system and transportation constraints, the net prices received for commodities produced, regulatory approvals and regulatory changes. In addition, there are contingencies that prevent contingent resources from being classified as reserves and there is uncertainty that it will be commercially viable to produce any portion of the Corporation's contingent resources. As a result of these uncertainties, there can be no assurance that these resource locations will ever be drilled or result in additional reserves or production for the Corporation. See *"Presentation of Oil and Gas Reserves and Resources"*, *"Risk Factors – Business and Operational Risks – Uncertainty of Reserves and Resource Estimates"* and *" – Drilling Locations"* and Appendix "A".

Forward-Looking Statements

Certain statements contained in this Annual Information Form constitute forward-looking statements and forward-looking information (collectively referred to as "**forward-looking statements**") within the meaning of applicable Canadian securities laws. The forward-looking statements contained in this Annual Information Form relate to future events or Birchcliff's future plans, operations or performance and are based on Birchcliff's current expectations, estimates, projections, beliefs and assumptions. Such forward-looking statements have been made by Birchcliff in light of the information available to it at the time the statements were made and reflect its experience and perception of historical trends. All statements and information other than historical fact may be forward-looking statements. Such forward-looking statements are often, but not always, identified by the use of words such as "seek", "plan", "expect", "project", "intend", "believe", "anticipate", "estimate", "forecast", "potential", "proposed", "predict", "budget", "continue", "targeting", "may", "will", "could", "might", "should" and other similar words and expressions.

By their nature, forward-looking 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. Accordingly, readers are cautioned not to place undue reliance on such forward-looking statements. Although Birchcliff believes that the expectations reflected in the forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct and Birchcliff makes no representation that actual results achieved will be the same in whole or in part as those set out in the forward-looking statements.

In particular, this Annual Information Form contains forward-looking statements relating to the following: Birchcliff's plans and other aspects of its anticipated future financial performance, operations, focus, objectives, strategies, opportunities, priorities and goals (including that Birchcliff is focused on its high-quality Montney/Doig Resource Play); statements regarding the 2019 Capital Program and the Corporation's proposed exploration and development activities and the timing thereof (including: estimates of capital expenditures and capital allocation; the number and types of wells to be drilled and brought on production; the focus of and the anticipated results from the program; the financial and operational flexibility of the program and that Birchcliff has the ability to expand its drilling program should commodity prices and/or economic conditions improve during 2019; and that Birchcliff may adjust the program to respond to changes in commodity prices and other material changes in the assumptions underlying the program); Birchcliff's expectation that the commodity price environment and economic and industry conditions will continue to influence the general development of its business in 2019; statements regarding the planned liquids-handling facility at the Pouce Coupe Gas Plant (including: the capacity of the facility; the anticipated timing for the completion of the facility; and that the facility will give Birchcliff the ability to grow its condensate production to 10,000 bbls/d in Pouce Coupe); the performance and other characteristics of Birchcliff's oil and natural gas properties and expected results from its assets (including the potential of Birchcliff's Montney/Doig Resource Play and statements that the Montney/Doig Resource Play is large enough to provide Birchcliff with an extensive inventory of repeatable and low-cost drilling opportunities that the Corporation expects will provide production and reserves growth for many years); Birchcliff's competitive position; Birchcliff's processing, transportation and marketing arrangements (including: that an additional tranche of service on TCPL's Canadian Mainline will become available later in 2019; the Corporation's ability to mitigate the impact of production curtailments on the NGTL System; that the Corporation enters into firm-service obligations for the transportation and processing of its natural gas, oil and NGLs production volumes in order to secure access to the infrastructure necessary to transport and process such volumes and renews, amends or enters into new firm-service agreements from time to time; and the Corporation's belief that it should generally secure firm transportation sufficient for its current and future growth plans); that Birchcliff has the ability to increase its natural gas production should commodity prices and economic conditions improve; Birchcliff's hedging activities, risk management strategy and use of risk management techniques; the treatment under and the impact of existing and proposed governmental regulatory regimes and tax laws (including: the impact of climate change and GHG legislation on the Corporation and its expectation that the incremental direct costs of compliance with GHG legislation between now and 2023 will not be material to the Corporation; and the Corporation's expectation that the Pouce Coupe Gas Plant will generate EPCs in respect of the 2018 financial year); estimates of decommissioning obligations; the information set forth under the heading *"Statement of Reserves Data and Other Oil and Gas Information"* and elsewhere in this Annual Information Form as it relates to the Corporation's reserves (including: estimates of reserves; estimates of the net present values of future net revenue associated with Birchcliff's reserves; price forecasts; the Corporation's development plans for its undeveloped reserves and the timing for the development of such reserves, including the number of wells forecast to be drilled and forecast facility expansions; abandonment and reclamation costs; future development costs, the anticipated funding of such costs and the Corporation's expectation that interest or other funding costs would not make the development of any of its properties uneconomic; statements regarding wells that are currently non-producing and the number of wells expected to be classified as proved developed producing reserves at the end of 2019; the amount of undeveloped lands on which Birchcliff expects the rights to explore, develop and exploit will expire within one year; Birchcliff's forward contracts and transportation and processing commitments; Birchcliff's income tax horizon; and estimates of production); projections of commodity prices and costs and supply and demand for crude oil and natural gas; expectations regarding the Corporation's ability to raise capital and to continually add to reserves through acquisitions and development; Birchcliff's dividend policy and the payment of dividends; statements relating to the Corporation's normal course issuer bid (including potential purchases under the bid and the cancellation of Common Shares purchased under the bid); statements regarding Birchcliff's Credit Facilities (including the timing of semi-annual reviews); and the information set forth in Appendix A and elsewhere as it relates to the Corporation's resources (including: estimates of Birchcliff's contingent resources, prospective resources and PIIP; estimates of the net present value associated with the best estimate of Birchcliff's development pending contingent resources; information regarding Birchcliff's development pending contingent resource projects, including development plans; estimates of the total costs to achieve commercial production and to fully develop a project; the timelines of such projects; estimates of the dates of first commercial production; and estimates of resource locations). Statements relating to reserves and resources are forward-looking as they involve the implied assessment, based on certain estimates and assumptions, that the reserves and resources exist in the quantities predicted or estimated and that the reserves and resources can profitably be produced in the future. See *"Presentation of Oil and Gas Reserves and Resources".*

With respect to the forward-looking statements contained in this Annual Information Form, assumptions have been made regarding, among other things: prevailing and future commodity prices and differentials, currency exchange rates, interest rates, inflation rates, royalty rates and tax rates; the state of the economy, financial markets and the exploration, development and production business; the political environment in which Birchcliff operates; the regulatory framework regarding royalties, taxes and environmental laws; the Corporation's ability to comply with existing and future environmental, climate change and other laws; future cash flow, debt and dividend levels; future operating, transportation, marketing, general and administrative and other expenses; Birchcliff's ability to access capital and obtain financing on acceptable terms; the timing and amount of capital expenditures and the sources of funding for capital expenditures and other activities; the sufficiency of budgeted capital expenditures to carry out planned operations; the successful and timely implementation of capital projects; results of future operations; Birchcliff's ability to continue to develop its assets and obtain the anticipated benefits therefrom; the performance of existing and future wells, well production rates and well decline rates; success rates for future drilling; reserves and resource volumes and Birchcliff's ability to replace and expand reserves through acquisition, development or exploration; the impact of competition on Birchcliff; the availability of, demand for and cost of labour, services and materials; the ability to obtain any necessary regulatory or other approvals in a timely manner; the satisfaction by third parties of their obligations to Birchcliff; the ability of Birchcliff to secure adequate processing and transportation for its products; Birchcliff's ability to market oil and gas; the availability of hedges on terms acceptable to Birchcliff; and natural gas market exposure. In addition to the foregoing assumptions, Birchcliff has made the following assumptions with respect to certain forward-looking statements contained in this Annual Information Form:

- Birchcliff's 2019 guidance assumes the following commodity prices during 2019: an average WTI price of US$56.00/bbl; an average WTI-MSW differential of $10.00/bbl; an average AECO price of $1.65/GJ; an average Dawn price of $3.40/GJ; an average NYMEX Henry Hub price of US$3.00/MMBtu; and an exchange rate (CDN$ to US$1) of 1.32.

- With respect to estimates of 2019 capital expenditures and Birchcliff's spending plans for 2019, such estimates and plans are based on the following:

  - Estimates of capital expenditures and any allocation thereof assume that the 2019 Capital Program will be carried out as currently contemplated.

  - Birchcliff makes acquisitions and dispositions in the ordinary course of business. Any acquisitions and dispositions completed could have an impact on Birchcliff's capital expenditures, production, cash flow, costs and debt, which impact could be material.

  - The amount and allocation of capital expenditures for exploration and development activities by area and the number and types of wells to be drilled and brought on production is dependent upon results achieved and is subject to review and modification by management on an ongoing basis throughout the year. Actual spending may vary due to a variety of factors, including commodity prices, economic conditions, results of operations and costs of labour, services and materials. Birchcliff will monitor economic conditions and commodity prices and, where deemed prudent, will adjust its capital programs to respond to changes in commodity prices and other material changes in the assumptions underlying such programs.

- With respect to statements of future wells to be drilled and brought on production, the key assumptions are: the continuing validity of the geological and other technical interpretations performed by Birchcliff's technical staff, which indicate that commercially economic volumes can be recovered from Birchcliff's lands as a result of drilling future wells; and that commodity prices and general economic conditions will warrant proceeding with the drilling of such wells.

- With respect to statements regarding the future potential and prospectivity of properties and assets, such statements assume: the continuing validity of the geological and other technical interpretations determined by Birchcliff's technical staff with respect to such properties; and that, over the long-term, commodity prices and general economic conditions will warrant proceeding with the exploration and development of such properties.

- With respect to estimates of reserves, resources and the net present values of future net revenue associated with Birchcliff's reserves and its best estimate of development pending contingent resources, the key assumption is the validity of the data used by Deloitte and McDaniel in their independent reserves evaluations.

Birchcliff's actual results, performance or achievements could differ materially from those anticipated in the forward-looking statements as a result of both known and unknown risks and uncertainties including, but not limited to: general economic, market and business conditions which will, among other things, impact the demand for and market prices of Birchcliff's products and Birchcliff's access to capital; volatility of crude oil and natural gas prices; fluctuations in currency and interest rates; stock market volatility; loss of market demand; an inability to access sufficient capital from internal and external sources; fluctuations in the costs of borrowing; operational risks and liabilities inherent in oil and natural gas operations; the occurrence of unexpected events such as fires, equipment failures and other similar events affecting Birchcliff or other parties whose operations or assets directly or indirectly affect Birchcliff; uncertainty that development activities in connection with its assets will be economical; uncertainties associated with estimating oil and natural gas reserves and resources; the accuracy of oil and natural gas reserves estimates and estimated production levels; geological, technical, drilling, construction and processing problems; uncertainty of geological and technical data; horizontal drilling and completions techniques and the failure of drilling results to meet expectations for reserves or production; uncertainties related to Birchcliff's future potential drilling locations; potential delays or changes in plans with respect to exploration or development projects or capital expenditures, including delays in the completion of gas plants and other facilities; the accuracy of cost estimates and variances in Birchcliff's actual costs and economic returns from those anticipated; incorrect assessments of the value of acquisitions and exploration and development programs; changes in tax laws, Crown royalty rates, environmental laws, carbon tax regimes, incentive programs and other regulations that affect the oil and natural gas industry and other actions by government authorities; an inability of the Corporation to comply with existing and future environmental, climate change and other laws; the cost of compliance with current and future environmental laws; political uncertainty and uncertainty associated with government policy changes; uncertainties and risks associated with pipeline restrictions and outages to third-party infrastructure that could cause disruptions to production; the lack of available pipeline capacity and an inability to secure adequate processing and transportation for Birchcliff's products; the inability to satisfy obligations under Birchcliff's firm marketing and transportation arrangements or other agreements; shortages in equipment and skilled personnel; the absence or loss of key employees; competition for, among other things, capital, acquisitions of reserves, undeveloped lands, equipment and skilled personnel; management of Birchcliff's growth; environmental risks, claims and liabilities; uncertainties associated with the outcome of litigation or other proceedings involving Birchcliff; unforeseen title defects; uncertainties associated with credit facilities and counterparty credit risk; non-performance or default by counterparties; risks associated with Birchcliff's risk management program and the risk that hedges on terms acceptable to Birchcliff may not be available; risks associated with the declaration and payment of dividends, including the discretion of Birchcliff's Board to declare dividends and change the Corporation's dividend policy; the failure to obtain any required approvals in a timely manner or at all; the failure to realize the anticipated benefits of acquisitions and dispositions and the risk of unforeseen difficulties in integrating acquired assets into Birchcliff's operations; negative public perception of the oil and natural gas industry, including transportation, hydraulic fracturing and fossil fuels; the Corporation's reliance on hydraulic fracturing; the availability of insurance and the risk that certain losses may not be insured; and breaches or failure of information systems and security (including risks associated with cyber-attacks).

Readers are cautioned that the foregoing lists of factors are not exhaustive. Additional information on these and other risk factors that could affect results of operations, financial performance or financial results are included under the heading *"Risk Factors"* in this Annual Information Form and in other reports filed with Canadian securities regulatory authorities from time to time.

This Annual Information Form may contain information that constitutes future-orientated financial information or financial outlook information (collectively, "**FOFI**") about Birchcliff's prospective results of operations, all of which is subject to the same assumptions, risk factors, limitations and qualifications as set forth above. Readers are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise or inaccurate and, as such, undue reliance should not be placed on FOFI. Birchcliff's actual results, performance and achievements could differ materially from those expressed in, or implied by, the FOFI. Birchcliff has included the FOFI in order to provide readers with a more complete perspective on Birchcliff's future operations and Birchcliff's current expectations relating to its future performance. Such information may not be appropriate for other purposes and readers are cautioned that any FOFI contained herein should not be used for purposes other than those for which it has been disclosed herein. FOFI contained herein was made as of the date of this Annual Information Form. Unless required by applicable laws, Birchcliff does not undertake any obligation to publicly update or revise any FOFI statements, whether as a result of new information, future events or otherwise.

Management has included the above summary of assumptions and risks related to forward-looking statements provided in this Annual Information Form in order to provide readers with a more complete perspective on Birchcliff's future operations. Readers are cautioned that this information may not be appropriate for other purposes.

The forward-looking statements contained in this Annual Information Form are expressly qualified by the foregoing cautionary statements. The forward-looking statements contained herein are made as of the date of this Annual Information Form. Unless required by applicable laws, Birchcliff does not undertake any obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

Access to Documents

Any document referred to in this Annual Information Form and described as being filed on the Corporation's SEDAR profile at www.sedar.com may be obtained free of charge from Birchcliff at Suite 1000, 600 – 3rd Avenue S.W., Calgary, Alberta T2P 0G5.

CORPORATE STRUCTURE

The Corporation was incorporated on July 6, 2004 under the ABCA as "1116463 Alberta Ltd." and on September 10, 2004, the Corporation amended its articles to change its name to "Birchcliff Energy Ltd." On January 18, 2005, the Corporation amalgamated under the ABCA with Scout Capital Corp., a public corporation, pursuant to a plan of arrangement under the ABCA to form an amalgamated corporation under the name "Birchcliff Energy Ltd." On May 31, 2005, the Corporation amalgamated under the ABCA with Veracel, a private company, pursuant to a plan of arrangement under the ABCA to form an amalgamated corporation under the name "Birchcliff Energy Ltd."

On August 3, 2012, the Corporation amended its articles to create the Series A Preferred Shares and the Series B Preferred Shares. On June 13, 2013, the Corporation amended its articles to create the Series C Preferred Shares. See *"Description of Capital Structure – Authorized Share Capital and Securities Outstanding – Preferred Shares"*.

The registered and head office of the Corporation is located at Suite 1000, 600 – 3rd Avenue S.W., Calgary, Alberta T2P 0G5.

The Corporation does not have any subsidiaries.

GENERAL DEVELOPMENT OF THE BUSINESS

Three Year History

A description of the significant developments in the business of the Corporation over the last three completed financial years is set forth below.

2016

On May 11, 2016, the aggregate limit of Birchcliff's credit facilities was decreased from $800 million to $750 million.

On July 28, 2016, the Corporation completed the Gordondale Acquisition for cash consideration of $613.5 million, after closing adjustments and other related costs. The assets acquired pursuant to the Gordondale Acquisition are primarily located in the Gordondale area of Alberta, approximately 100 km northwest of Grande Prairie, Alberta and are located within Birchcliff's Montney/Doig Resource Play in the Peace River Arch area of Alberta. The assets included high working interest operated production and a large contiguous land base which is immediately adjacent to Birchcliff's existing Pouce Coupe properties. Pursuant to the Gordondale Acquisition, the Corporation acquired 143.5 (84.7 net) sections of land and approximately 26,000 boe/d (41% oil and NGLs) of production as at the closing date of the acquisition. The effective date of the Gordondale Acquisition was January 1, 2016.

The purchase price for the Gordondale Acquisition was primarily funded through the 2016 Public Offering and the 2016 Private Placement which closed concurrently on July 13, 2016. The aggregate gross proceeds of approximately $690.8 million were held in escrow pending completion of the Gordondale Acquisition. In connection with the closing of the Gordondale Acquisition on July 28, 2016, each Subscription Receipt was exchanged for one Common Share and the gross proceeds from the 2016 Public Offering and the 2016 Private Placement were released from escrow in order for Birchcliff to complete the Gordondale Acquisition. In connection with the closing of the Gordondale Acquisition, the Corporation's extendible revolving credit facilities were amended to increase the borrowing base to $950 million from $750 million.

On August 10, 2016, Ms. Rebecca J. Morley was appointed as a director of the Corporation.

On November 9, 2016, the Corporation announced that the Board had approved a quarterly dividend policy in respect of its Common Shares. See *"Dividend and Distribution Policy".* In addition, the Corporation announced that it had adopted an ongoing hedging strategy.

2017

On March 1, 2017, the Corporation announced that the Board had declared a quarterly cash dividend of $0.025 per Common Share for the quarter ending March 31, 2017 on the Corporation's outstanding Common Shares. This was the first dividend paid by the Corporation on its Common Shares. See *"Dividend and Distribution Policy".*

On March 21, 2017, the Corporation announced that it would pursue the sale of its Charlie Lake light oil resource play (the "**Charlie Lake Light Oil Resource Play**") and that it had engaged a marketing agent to seek potential purchasers. The Corporation subsequently disposed of the majority of its assets on the Charlie Lake Light Oil Resource Play pursuant to the Worsley Disposition, which closed on August 31, 2017, and the Progress Disposition, which closed on October 2, 2017, as discussed in further detail below.

On March 27, 2017, the Corporation announced that it had entered into agreements with TCPL for the firm service transportation of an aggregate of 175,000 GJ/d of natural gas on TCPL's Canadian Mainline for a 10-year term. See *"Description of the Business – Transportation Arrangements – Natural Gas".*

On May 10, 2017, the Corporation and its syndicate of lenders agreed to an extension of the maturity dates of the Credit Facilities from May 11, 2018 to May 11, 2020 and to the borrowing base remaining unchanged at $950 million.

On May 11, 2017, Mr. James W. Surbey was elected as a director of the Corporation at the annual and special meeting of shareholders. On June 30, 2017, Mr. Surbey retired as the Vice-President, Corporate Development and Corporate Secretary of the Corporation.

On August 1, 2017, the Corporation announced that it had entered into a definitive purchase and sale agreement with a private oil and gas company with respect to the Worsley Disposition. On August 31, 2017, the Corporation completed the Worsley Disposition for total consideration of approximately $100 million (before adjustments), consisting of: (i) cash consideration of $90 million; and (i) securities of affiliates of the purchaser with a total value of $10 million. The effective date of the Worsley Disposition was July 1, 2017.

On August 10, 2017, the Corporation announced that it had entered into a definitive purchase and sale agreement with respect to the Progress Disposition. On October 2, 2017, the Corporation completed the Progress Disposition for total consideration of $31.7 million (before adjustments).

In September 2017, Phase V of the Pouce Coupe Gas Plant commenced operations, increasing the total processing capacity of the Pouce Coupe Gas Plant to 260 MMcf/d from 180 MMcf/d.

On November 8, 2017, Ms. Debra A. Gerlach was appointed as a director of the Corporation.

2018

On April 3, 2018, the Corporation and AltaGas announced that they had entered into a definitive agreement for a new long-term natural gas processing arrangement (the "**Gordondale Processing Arrangement**") effective January 1, 2018 for natural gas processed at the Gordondale Gas Plant. See *"Description of the Business – Processing Arrangements".*

On April 27, 2018, the Corporation and its syndicate of lenders agreed to: (i) an extension of the maturity dates of each of the Syndicated Credit Facility and the Working Capital Facility from May 11, 2020 to May 11, 2021; (ii) the borrowing base remaining unchanged at $950 million; and (iii) increasing the Working Capital Facility to $100 million (from $50 million) with a corresponding reduction in the Syndicated Credit Facility to $850 million (from $900 million). For additional information regarding the Credit Facilities, see "*Description of Capital Structure – Credit Facilities"*.

On May 10, 2018, Mr. Larry A. Shaw ceased to be a director of the Corporation as he did not stand for re-election at the Corporation's annual and special meeting of shareholders held on the same date.

In August 2018, Phase VI of the Pouce Coupe Gas Plant commenced operations, increasing the total processing capacity of the Pouce Coupe Gas Plant to 340 MMcf/d from 260 MMcf/d.

On November 14, 2018, the Corporation announced that it had entered into a definitive purchase and sale agreement with respect to the Pouce Coupe Acquisition, which acquisition subsequently closed on January 3, 2019. See *"General Development of the Business – Recent Developments".*

On December 14, 2018, Ms. Stacey E. McDonald was appointed as a director of the Corporation and Ms. Rebecca J. Morley resigned as a director of the Corporation.

Recent Developments

On January 3, 2019, the Corporation completed the Pouce Coupe Acquisition. Pursuant to the Pouce Coupe Acquisition, the Corporation acquired 18 gross (15.1 net) contiguous sections of Montney land located between the Corporation's existing Pouce Coupe and Gordondale properties, as well as various other non-Montney lands and other assets, for total cash consideration of $39 million.

On February 13, 2019, the Corporation announced that the Board had approved a capital budget of $204 million for 2019. The Corporation's 2019 capital program (the "**2019 Capital Program**") is focused on its high-value light oil assets in Gordondale and its condensate-rich assets in Pouce Coupe. The 2019 Capital Program contemplates the drilling of 17 (17.0 net) wells and the bringing on production of 26.0 (26.0 net) wells during 2019. In addition, funds will be directed to increasing the inlet liquids-handling capacity at the Pouce Coupe Gas Plant and to other infrastructure enhancement projects for future growth.

Birchcliff expects that the commodity price environment and economic and industry conditions will continue to influence the general development of its business in 2019. Birchcliff will monitor economic conditions and commodity prices and, where deemed prudent, will adjust the 2019 Capital Program to respond to changes in commodity prices and other material changes in the assumptions underlying such program. In addition, the Corporation may make adjustments to its other business activities as appropriate. The 2019 Capital Program has been designed with financial and operational flexibility such that Birchcliff has the ability to expand its drilling program should commodity prices and/or economic conditions improve during 2019. See *"Special Notes to Reader – Forward-Looking Statements".*

Significant Acquisitions

The Corporation did not complete any significant acquisitions during the financial year ended December 31, 2018 for which disclosure is required under Part 8 of NI 51-102.

The Corporation continues to evaluate potential acquisitions of all types of petroleum and natural gas and other energy-related assets and/or companies as part of its ongoing business. The Corporation is regularly in the process of evaluating several potential acquisitions at any one time, which individually or together could be material. Birchcliff cannot predict whether any current or future opportunities will result in one or more acquisitions for the Corporation. In addition, the Corporation may in the future complete financings of equity or debt (which may be convertible into equity) for purposes that may include financing of acquisitions, Birchcliff's operations and capital expenditures and the repayment of indebtedness. See *"Risk Factors".*

DESCRIPTION OF THE BUSINESS

General

The Corporation is an intermediate oil and natural gas company based in Calgary, Alberta that is engaged in the business of exploring for, developing and producing natural gas, crude oil and NGLs in the Western Canadian Sedimentary Basin with operations concentrated within its one core area, the Peace River Arch of Alberta.

Within the Peace River Arch, Birchcliff is focused on its high-quality Montney/Doig Resource Play and the exploration and development of its low-cost natural gas, crude oil and liquids-rich assets on the play. The Corporation's Montney/Doig Resource Play is large enough to provide it with an extensive inventory of repeatable and low-cost drilling opportunities that the Corporation expects will provide production and reserves growth for many years.

Within the Montney/Doig Resource Play, the Corporation's operations are primarily concentrated in the Pouce Coupe and Gordondale areas of Alberta where it owns large contiguous blocks of high working interest land. At December 31, 2018, the Corporation operated 99% of its production. In addition, the Corporation owns and controls many of the significant facilities and infrastructure it relies upon to handle the majority of its production, including its 100% owned and operated Pouce Coupe Gas Plant.

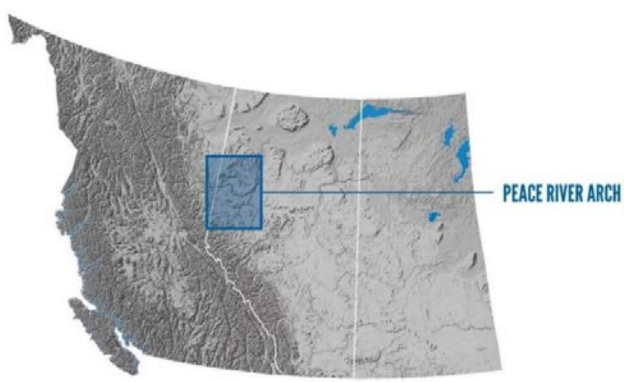
The Common Shares, the Series A Preferred Shares and the Series C Preferred Shares are listed for trading on the TSX under the trading symbols "BIR", "BIR.PR.A" and "BIR.PR.C", respectively, and the Common Shares are included in the S&P/TSX Composite Index.

Principal Properties

The following is a description of the Corporation's principal oil and natural gas properties as at December 31, 2018. Unless otherwise stated, production volumes presented below are the Corporation's average gross sales volumes for the period indicated, meaning Birchcliff's working interest (operating or non-operating) share before the deduction of royalties and without including any royalty interests of Birchcliff.

Peace River Arch

Birchcliff's operations are concentrated within its one core area, the Peace River Arch, which is centred northwest of Grande Prairie, Alberta, adjacent to the Alberta/British Columbia border. The Peace River Arch is one of the most prolific natural gas and oil producing areas of the Western Canadian Sedimentary Basin and is generally characterized by multiple horizons with a myriad of structural, stratigraphic and hydrodynamic traps. The Peace River Arch is highlighted by the Deep Basin hydrocarbon trapping phenomena. The Deep Basin is a hydrodynamic or permeability trap where the water in the updip position cannot travel through the fine grained reservoirs with characteristics that include overpressured reservoirs, continuous hydrocarbon columns, low water production and long-life reserves with low terminal declines. The Peace River Arch provides all-season access that allows the Corporation to drill, equip and tie-in wells on an almost continuous basis.



The Montney/Doig Resource Play

Overview

The Montney/Doig Resource Play is considered by management to be one of the premier resource plays in North America. Birchcliff's Montney/Doig Resource Play is centred approximately 95 km northwest of Grande Prairie, Alberta. Within the Montney/Doig Resource Play, the Corporation is focused on two key operating areas, Pouce Coupe and Gordondale. These two key operating areas are essentially contiguous and collectively represented approximately 99% of the Corporation's total annual average production in 2018. The Corporation has established two geographically-organized teams, the Pouce Coupe team and the Gordondale team, to manage these two key operating areas. These teams each have a full complement of highly skilled technical professionals, including engineers, geoscientists and landmen.

At December 31, 2018, Birchcliff held 367.4 gross sections of land on the Montney/Doig Resource Play. During the financial year ended December 31, 2018, the Montney/Doig Resource Play accounted for essentially 100% of the Corporation's production, capital expenditures and reserves.

Attributes

Birchcliff characterizes its Montney/Doig Resource Play as a regionally pervasive, continuous, low-permeability hydrocarbon accumulation or system that typically requires intensive stimulation to produce. The production characteristics of this play generally include steep initial declines that rapidly trend to much lower decline rates, yielding long-life production and reserves. The play exhibits a statistical distribution of estimated ultimate recoveries and therefore provides a repeatable distribution of drilling opportunities. Birchcliff's Montney/Doig Resource Play is ideally suited for the application of horizontal drilling and multi-stage fracture stimulation technology.

As more wells are drilled into a resource play, there is a substantial decrease in both the geological and technical risks. Over the past 14 years, Birchcliff has worked to de-risk its Montney/Doig Resource Play by drilling both vertical and horizontal exploration wells in order to develop an in-depth understanding of the oil and gas pools, rock properties and petrophysical characteristics and reservoir parameters. The Corporation designs, tests and evaluates its drilling, completion and production technologies and practices to achieve continual improvements in productivity and expected ultimate recoveries in order to drive down capital and operating costs. The Corporation's pool delineation strategy de-risks future development and helps to reduce future costs as new well pads and infrastructure are designed and built to support multiple horizontal well locations and increased production.

Geology

The Montney/Doig Resource Play in Birchcliff's areas of operations is approximately 300 metres (1,000 feet) thick. The play has a large areal extent covering in excess of 50,000 square miles. The Montney/Doig is composed of a high percentage of hard minerals and a very low percentage of clay minerals resulting in exceptional "fracability". This, combined with the current stress regime, results in the rock shattering more like glass in a complex fracture style versus a simple bi-wing style. The rock parameters also yield exceptional fracture stability; the fractures stay open due to low proppant embedment. This is a key contributing factor to the low terminal declines and large estimated ultimate recoveries of the play. Unlike most shale plays that are predominantly shale, the Montney/Doig is classified by management as a hybrid resource play because it is comprised of hydrocarbon-saturated rock with both tight silt and sand reservoir rock interlayered with shale source rock. This results in relatively high permeability and productivity rates.

Hydrodynamics is another important attribute for resource plays. A large portion of the Montney/Doig Resource Play is over-pressured which reduces the potential for significant water production. The Pouce Coupe and Gordondale areas are predominantly over-pressured which also results in higher hydrocarbons in-place. The Montney and a majority of the Doig were deposited in a lower to middle shore face environment that is regionally extensive and results in a widespread style deposit that provides for more repeatable results.

The Montney/Doig Resource Play exists in two geological formations (the Montney and the Doig) and Birchcliff has divided the geologic column in its areas of operations into six drilling intervals from the youngest (top) to the oldest (bottom): (i) the Basal Doig/Upper Montney; (ii) the Montney D4; (iii) the Montney D3; (iv) the Montney D2; (v) the Montney D1; and (vi) the Montney C. Part of Birchcliff's long-term strategy is to continue to explore and delineate the Montney/Doig Resource Play, both geographically and stratigraphically. At December 31, 2018, the Corporation has successfully drilled and cased an aggregate of 385.0 (380.6 net) Montney/Doig horizontal wells on the Montney/Doig Resource Play. Of these wells, an aggregate of 372 (367.6 net) wells have been completed and brought on production (including 87 (81.8 net) wells that were acquired in connection with the Gordondale Acquisition), consisting of 72 (71.3 net) wells in the Basal Doig/Upper Montney interval, 12 (12.0 net) wells in the Montney D4 interval, 22 (22.0 net) wells in the Montney D2 interval, 264 (260.3 net) wells in the Montney D1 interval and 2 (2.0 net) wells in the Montney C interval. To date, the Corporation has not drilled any wells in the Montney D3 interval.

Key Operating Areas

The following is a brief description of the Corporation's two key operating areas within the Montney/Doig Resource Play:

Pouce Coupe

The Pouce Coupe key operating area is located west and northwest of Grande Prairie, Alberta and consists of the Corporation's properties in Pouce Coupe and Elmworth. At December 31, 2018, the Corporation held an aggregate of 350.9 (331.6 net) sections of land in the Pouce Coupe key operating area. Annual average production in 2018 for the Pouce Coupe key operating area was 48,943 boe/d (48,734 boe/d in Pouce Coupe and 209 boe/d in Elmworth).

In 2018, the Pouce Coupe key operating area accounted for approximately:

- 61% of the Corporation's total capital expenditures;
- 63% of the Corporation's total corporate annual average production; and
- 74% of the Corporation's total annual average natural gas production, less than 1% of the Corporation's total annual average light oil production and 29% of the Corporation's total annual average NGLs production.

In 2018, the Corporation drilled 19 (19.0 net) Montney/Doig horizontal natural gas wells in the Pouce Coupe area and completed the 80 MMcf/d Phase VI expansion of the Pouce Coupe Gas Plant. The Corporation's 2019 Capital Program contemplates the drilling of 9 (9.0 net) wells and the bringing on production of 14 (14.0 net) wells in the Pouce Coupe area in 2019, as well as directing funds to increasing the inlet liquids-handling capacity of the Pouce Coupe Gas Plant. See *"General Development of the Business – Recent Developments"* for further information regarding the 2019 Capital Program.

Significant infrastructure being used by Birchcliff in the area includes the Pouce Coupe Gas Plant. See *"Description of the Business – Facilities"* and *"Description of the Business – Processing Arrangements"* for further information regarding the Pouce Coupe Gas Plant.

Gordondale

The Gordondale key operating area is located northwest of Grande Prairie, Alberta and consists solely of the Corporation's properties in Gordondale. At December 31, 2018, the Corporation held an aggregate of 139.0 (88.4 net) sections of land in the Gordondale key operating area. Annual average production in 2018 for the Gordondale key operating area was 28,028 boe/d.

In 2018, the Gordondale key operating area accounted for approximately:

- 39% of the Corporation's total capital expenditures;
- 36% of the Corporation's total corporate annual average production; and
- 25% of the Corporation's total annual average natural gas production, 99% of the Corporation's total annual average light oil production and 71% of the Corporation's total annual average NGLs production.

In 2018, the Corporation drilled 17 (17.0 net) Montney horizontal oil wells in the Gordondale area. The Corporation's 2019 Capital Program contemplates the drilling of 8 (8.0 net) wells and the bringing on production of 12 (12.0 net) wells in the Gordondale area in 2019. See *"General Development of the Business – Recent Developments"* for further information regarding the 2019 Capital Program.

Significant infrastructure being used by Birchcliff in the area includes the Gordondale Gas Plant and Pembina's fractionation facility at Redwater, Alberta (the "**Pembina Facility**"). See *"Description of the Business – Processing Arrangements"* for further information regarding Birchcliff's processing arrangements at these facilities.

Other Properties

In addition to Pouce Coupe and Gordondale, the Corporation also has other miscellaneous properties, including in the Balsam, Bonanza, Hill, Teepee and Bezanson areas of Alberta, none of which are material to the Corporation. Annual average production in 2018 for the Corporation's other properties was 125 boe/d.

Landholdings

The Corporation's land base primarily consists of large contiguous blocks of high working interest acreage located near facilities owned and/or operated by Birchcliff or near third-party infrastructure. The Corporation's land activities during 2018 included: (i) the acquisition of 35.0 (34.2 net) sections of Crown and third-party lands; and (ii) the disposition of 143.1 (131.2 net) sections of land pursuant to various non-core dispositions. The Corporation's undeveloped land base at December 31, 2018 was 200,789.4 (178,296.7 net) acres, or 313.7 (278.6 net) sections, with an 89% average working interest.

Drilling Program and Technology

During 2018, Birchcliff drilled 36 (36.0 net) wells and brought 28 (28.0 net) wells on production. All wells drilled in 2018 were drilled on multi-well pads, which allows Birchcliff to reduce its per well costs and environmental footprint. Birchcliff actively employs the evolving technology utilized by the industry regarding horizontal well drilling and the related multi-stage fracture stimulation technology.

Facilities

The following table sets forth the major facilities in which the Corporation held an interest at December 31, 2018:

Facility Description[(1)]	Area and Location	Birchcliff Operated	Working Interest
Pouce Coupe Gas Plant	Pouce Coupe (03-22-78-12W6M)	Yes	100%
Oil battery	Gordondale (02-06-79-11W6M)	Yes	100%
Oil battery	Gordondale (07-29-78-11W6M)	Yes	100%
Gas plant	Gordondale (01-01-78-10W6M)	No	~13%

(1) The Corporation does not have a working interest in either the Gordondale Gas Plant owned by AltaGas or the Pembina Facility owned by Pembina. Accordingly, neither of these facilities are included in the table above.

At December 31, 2018, Birchcliff also held various interests in numerous other gas plants, oil batteries, compressors, facilities and infrastructure.

The following is a more detailed description of the Pouce Coupe Gas Plant:

Pouce Coupe Gas Plant

Birchcliff's 100% owned and operated Pouce Coupe Gas Plant, which is currently licensed to process up to 340 MMcf/d of natural gas, is located in the heart of the Corporation's Montney/Doig Resource Play in the Pouce Coupe area. The strategically situated site for the Pouce Coupe Gas Plant enables the Corporation to control and operate all essential infrastructure from wellhead to sales point. The low per unit operating costs of the Pouce Coupe Gas Plant and related infrastructure give the Corporation a strong competitive advantage over other producers paying for third-party natural gas processing.

The Pouce Coupe Gas Plant was constructed in six separate phases as set forth in the table below:

Phase	Phase Capacity	Total Combined Processing Capacity	Commencement of Operations
Phase I	30 MMcf/d	30 MMcf/d	March 2010
Phase II	30 MMcf/d	60 MMcf/d	November 2010
Phase III	90 MMcf/d	150 MMcf/d	October 2012
Phase IV	30 MMcf/d	180 MMcf/d	September 2014
Phase V	80 MMcf/d	260 MMcf/d	September 2017
Phase VI	80 MMcf/d	340 MMcf/d	August 2018

In the fourth quarter of 2018, the Corporation completed the re-configuration of Phases V and VI to provide for shallow-cut capability which allows the Corporation to extract C3+ from the natural gas stream. In addition, the Corporation has committed to the construction of a 20,000 bbls/d inlet liquids-handling facility at the Pouce Coupe Gas Plant. This facility is anticipated to be online in the third quarter of 2020 and will give the Corporation the ability to grow its condensate production in Pouce Coupe from 3,000 bbls/d to 10,000 bbls/d.

The Pouce Coupe Gas Plant meets or exceeds all AER and Alberta Environment requirements. The facility employs energy efficient equipment to optimize performance and keep operating costs low. The Pouce Coupe Gas Plant uses an amine system to remove sulphur content and refrigeration to meet pipeline dew point specifications. Acid gas is injected into a high quality reservoir via two wells located at or adjacent to the site of the Pouce Coupe Gas Plant.

Processing Arrangements

Pouce Coupe Key Operating Area

The vast majority of the Corporation’s natural gas production from the Pouce Coupe key operating area is processed at the Pouce Coupe Gas Plant, with a de minimis amount being processed at third party facilities. The natural gas processed at the Pouce Coupe Gas Plant is delivered via the NGTL System to NIT. The natural gas may then be sold at AECO or it may be delivered via the NGTL System to Empress for transport to Dawn via TCPL’s Canadian Mainline, where it may then be sold.

Condensate and other NGLs extracted from the natural gas stream at the Pouce Coupe Gas Plant are delivered to the Pembina Peace Pipeline by pipeline or truck.

Gordondale Key Operating Area

The vast majority of the Corporation’s natural gas production from the Gordondale key operating area is processed at the Gordondale Gas Plant, with a de minimis amount being processed at other third-party facilities. Under the Gordondale Processing Arrangement, Birchcliff is provided with up to 120 MMcf/d of natural gas processing on a firm-service basis at the Gordondale Gas Plant, and Birchcliff’s take-or-pay obligation is 100 MMcf/d. The term of the Gordondale Processing Arrangement is for at least 15 years, subject to extension in accordance with the terms of the agreement. The effective date of the Gordondale Processing Arrangement is January 1, 2018. The natural gas produced at the Gordondale Gas Plant is delivered to NIT or Dawn in a similar manner as described above for Pouce Coupe.

NGLs extracted from the natural gas stream are primarily processed at the Pembina Facility where Birchcliff has access to and is responsible for the costs of 9,000 bbls/d of fractionation capacity.

The vast majority of the Corporation’s light oil production from the Gordondale key operating area is processed at the Corporation’s oil batteries and then delivered to the Pembina Peace Pipeline by pipeline or truck.

Transportation Arrangements

Natural Gas

The vast majority of the Corporation's natural gas production is transported to market on either the NGTL System to various delivery points or on TCPL's Canadian Mainline to Dawn. The Corporation employs a combination of firm and interruptible receipt pipeline service to deliver such production.

For 2019, the Corporation has approximately 440 MMcf/d of firm transportation receipt service on the NGTL System. The Corporation's transportation commitments are in excess of its forecast annual average production for 2019 as a result of excess processing capacity at the Pouce Coupe Gas Plant. This excess processing and transportation capacity gives the Corporation the ability to increase its natural gas production should commodity prices and economic conditions improve.

In March 2017, the Corporation entered into agreements with TCPL for the firm service transportation of an aggregate of 175,000 GJ/d of natural gas on TCPL's Canadian Mainline for a 10-year term, whereby natural gas is transported from the Empress receipt point in Alberta to the Dawn trading hub located in Southern Ontario. The toll for the Empress to Dawn portion of the service is $0.77/GJ plus fuel. The first tranche of this service (120,000 GJ/d) became available to Birchcliff on November 1, 2017 and the second tranche became available on November 1, 2018 (30,000 GJ/d), with the final tranche becoming available on November 1, 2019 (25,000 GJ/d).

The Pouce Coupe Gas Plant is also tied into the Alliance pipeline through Birchcliff's meter station located at Moose Creek, Alberta. Although the Corporation does not have transportation service on the Alliance pipeline, this connection provides the Corporation with the ability to try and purchase transportation service, either from Alliance directly or other third parties. Typically, such arrangements are done on a short-term basis and are subject to availability and Birchcliff being able to obtain an acceptable price for such service. These short-term arrangements can help the Corporation to mitigate the impact of production curtailments on the NGTL System.

Light Oil and NGLs

The vast majority of the Corporation's light oil production is transported on the Pembina Peace Pipeline to Edmonton, Alberta. The vast majority of the Corporation's NGLs production is transported on the Pembina Northern Pipeline to Fort Saskatchewan, Alberta.

Marketing and Risk Management

Natural Gas

The Corporation's natural gas production is primarily sold to third-party natural gas marketers at the AECO daily index price or the Dawn daily index price. From November 1, 2017 to November 1, 2018, the Corporation assigned its TCPL service from Empress to Dawn for a one-year term ending November 1, 2018. During this term, the marketers delivered Birchcliff's natural gas to Dawn and paid Birchcliff the Dawn daily index price, less the Empress to Dawn toll and fuel costs. Under these agreements, each marketer had the option to divert the natural gas to secondary delivery points to optimize the price received for the natural gas. In such instances, Birchcliff received between 60% and 80% of the optimized value obtained for the natural gas.

Birchcliff also has sales agreements with a third party marketer to sell and deliver into the Alliance pipeline system approximately 5 MMcf/d of natural gas under contracts which commenced April 1, 2017 and expire October 31, 2020, which is sold at Alliance's Trading Pool daily index price.

Light Oil and NGLs

The Corporation's light oil production is primarily sold to crude oil marketers on a monthly basis. The pricing is either based on an index price or is a netback or posted price provided by the marketer.

The majority of the Corporation's NGLs production is currently sold to marketers under contracts that commence on April 1 of the calendar year and run for one or two years. The pricing is typically based on available index prices.

In addition, the Corporation also sells ethane and propane under a long-term contract extending to 2026. Under this contract, ethane is sold at an indexed-based price and propane is priced at the buyer's posted propane price.

Risk Management

The Corporation also engages in risk management hedging which is done using financial instruments and physical delivery sales contracts which are separate from the Corporation's marketing contracts. For further information regarding the Corporation's risk management activities, see *"Statement of Reserves Data and Other Oil and Gas Information – Other Oil and Gas Information – Forward Contracts"* and the Corporation's audited annual financial statements and related management's discussion and analysis for the year ended December 31, 2018.

Petroleum and Natural Gas Sales

During 2018, the Corporation's annual average production was 77,096 boe/d and the only products produced and sold by the Corporation were natural gas, light oil and NGLs. During 2018, production consisted of approximately 80% natural gas, 6% light oil and 14% NGLs.

Excluding the effects of hedges using financial instruments but including the effects of physical delivery contracts, the Corporation's average realized sales price during 2018 was $2.45/Mcf for natural gas (2017: $2.72/Mcf), $68.66/bbl for light oil (2017: $61.42/bbl) and $44.66/bbl for NGLs (2017: $33.39/bbl). The following table sets forth the aggregate sales for the Corporation's natural gas, light oil and NGLs for the years ended December 31, 2018 and December 31, 2017:

Product	2018 Sales(1)	2017 Sales(1)
Natural Gas	$332,978,950	$318,789,983
Light Oil	$122,118,041	$134,596,611
NGLs	$166,193,962	$103,244,627

(1) The amounts set forth in the table above for 2018 and 2017 exclude the effects of hedges using financial instruments but include the effects of physical delivery contracts and exclude royalty revenues.

During 2018, approximately 61% of the Corporation's natural gas was exposed to AECO pricing, 31% was exposed to Dawn pricing and 8% was exposed to the Alliance Trading Pool daily index pricing. For further information regarding the Corporation's natural gas market diversification, see the Corporation's management's discussion and analysis for the year ended December 31, 2018.

The Corporation's revenues are highly dependent upon the prices that it receives for oil, natural gas and NGLs and such prices are closely correlated to the benchmark prices of oil and natural gas. See *"Risk Factors – Financial Risks and Risks Relating to Economic Conditions – Prices, Markets and Marketing".*

Competitive Conditions

The oil and natural gas industry is highly competitive in all of its phases. The Corporation competes with numerous other entities for land, acquisitions of reserves, access to drilling and service rigs and other equipment, access to transportation and skilled technical and operating personnel, among other things. The Corporation's competitors include companies that have more financial resources, staff and facilities than those of the Corporation.

Management believes that the Corporation has a competitive advantage in its focus area of the Peace River Arch area of Alberta based upon the infrastructure and land base it controls. In addition, management believes that it has a competitive advantage based on the experience it has developed on the Montney/Doig Resource Play. The Corporation attempts to enhance its competitive position by operating in areas where it believes its technical personnel are able to reduce some of the risks associated with exploration, production and marketing because such personnel are familiar with the areas. See "*Risk Factors – Business and Operational Risks – Competition*".

Seasonal and Cyclical Factors

The level of activity in the Canadian oil and natural gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments may enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Road bans and other restrictions generally result in a reduction of drilling and exploratory activities and may also result in the shut-in of some of the Corporation's production if not otherwise tied-in. In addition, certain oil and natural gas producing properties are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. Further, extreme cold weather, heavy snowfall and heavy rainfall may restrict the Corporation's ability to access its properties and cause operational difficulties. Accordingly, seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and a corresponding variability in the Corporation's production. See *"Risk Factors – Business and Operational Risks – Seasonality and Extreme Weather Conditions"*.

In addition, the Corporation's operational results and financial condition are highly dependent on the prices it receives for its oil and natural gas production. Oil and natural gas prices are subject to large fluctuations and have been depressed during recent years and at times, Canadian oil and natural gas prices have seen significant pricing discounts relative to global benchmark prices. Commodity prices are determined by supply and demand factors, including weather and general economic conditions, as well as egress and processing constraints and conditions in other oil and natural gas regions. Declines in commodity prices adversely affect the Corporation's business and financial condition. See *"Risk Factors – Financial Risks and Risks Relating to Economic Conditions – Prices, Markets and Marketing".* The Corporation attempts to mitigate such price risk through closely monitoring the various commodity markets, diversifying its sales portfolio and establishing hedging programs, as deemed necessary, to fix netbacks on its production volumes. See *"Statement of Reserves Data and Other Oil and Gas Information – Forward Contracts".*

Environmental Protection

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with oil and natural gas industry operations. In addition, such legislation sets out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites. Compliance with environmental legislation can require significant expenditures and/or result in operational restrictions. A breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. In addition, a breach may result in the suspension or revocation of necessary licences and authorizations and/or the Corporation being subject to interim compliance measures, all of which may restrict the Corporation's ability to conduct operations. Further, the Corporation could be subject to civil liability for pollution damage. See *"Risk Factors – Regulatory, Political and Environmental Risks"*.

Environmental Costs and Decommissioning Obligations

The Corporation is currently subject to the carbon levy legislation in Alberta as described under the heading *"Industry Conditions – Climate Change Regulation – Alberta"*; however, the Corporation is currently exempt from paying the carbon levy until 2023 under available exemptions. The Corporation currently has one facility, namely the Pouce Coupe Gas Plant, that is subject to the CCIR that is described under the heading *"Industry Conditions – Climate Change Regulation – Alberta"*. As the Pouce Coupe Gas Plant is subject to the CCIR, it is currently exempt from paying the carbon levy.

At the present time, the operational and financial impacts of complying with such GHG legislation are not material to the Corporation. Based on currently available information, the Corporation does not expect the incremental direct costs of compliance between now and 2023 to be material to the Corporation, taking into account, among other things, the exemptions that are currently available to the Corporation until 2023, the benchmarking data that is currently available, forecast increases in carbon pricing, forecast throughput at the Corporation's facilities and expected future emissions performance of the Corporation's facilities. Looking longer-term (2023 and beyond) and assuming that the current legislation is still in effect in its present form, compliance costs are expected to continue to increase as the exemptions from the Alberta carbon levy available to the Corporation expire. The Corporation will continue to evaluate these longer-term developments in order to assess the potential financial and operational implications. Given the multitude of variables that could cause outcomes to change, it is not currently possible to predict the future incremental compliance costs with any certainty. See *"Special Notes to Reader – Forward-Looking Statements".*

The costs of complying with existing or future environmental legislation or regulations, including those relating to climate change and GHG emissions, may have a material adverse effect on the Corporation's financial condition or results of operations. Future changes in environmental legislation could occur and result in stricter standards and enforcement, larger fines and liability and increased capital expenditures and operating costs. At December 31, 2018, the Corporation has not recorded any material costs and liabilities relating to GHG or environmental protection legislation or any material environmental incidents. See *"Special Notes to Reader – Forward-Looking Statements", "Industry Conditions"* and *"Risk Factors – Regulatory, Political and Environmental Risks"*.

As a result of its net ownership interest in oil and natural gas properties and equipment, including well sites, processing facilities and gathering systems, the Corporation incurs decommissioning obligations. The Corporation's decommissioning obligation at December 31, 2018 was $129.3 million, calculated on a discounted fair value basis using a risk-free rate of 2.36% and an inflation rate of 2.0%. Additional information on the Corporation's decommissioning obligations is available in the Corporation's audited annual financial statements for the year ended December 31, 2018.

Social and Environmental Policies

A copy of the Corporation's 2017 Corporate Responsibility Report, which provides additional information regarding Birchcliff's corporate responsibility initiatives, is available on the Corporation's website at www.birchcliffenergy.com.

Health, Safety and Environmental Programs

Birchcliff is committed to constantly evolving and improving its health, safety and environmental management program and conducting its activities in a manner that safeguards its employees, contractors, representatives, the environment and the public at large. The Corporation has an active program to monitor and comply with health, safety and environmental laws, rules and regulations applicable to its operations.

The Corporation's corporate policies require operational activities to be conducted in a manner which meets or exceeds regulatory requirements and industry standards to safeguard the environment and protect employees, contractors and the public at large. Employees receive pertinent health, safety and environmental training for their roles. Birchcliff conducts operational audits and assessments to identify risks and takes steps to reduce or prevent incidents. The Corporation has developed emergency response plans in conjunction with local authorities, emergency services and the communities in which it operates in order to be prepared to effectively respond to an incident should one arise. In addition, the Corporation rigorously conducts annual emergency response exercises and training for its staff that exceed regulatory requirements.

Birchcliff participates in Alberta's COR Safety Program and has received and maintained a COR certification since 2011. A COR certification demonstrates that the employer's health and safety management system has been evaluated by a certified auditor and meets provincial standards, as established by Occupational Health and Safety (Alberta). Maintaining a COR certification requires a commitment to continuous improvement in health, safety and environment management practices, including sound planning and implementation. Birchcliff's health and safety program is audited externally every 3 years by an independent auditor and internally every year by a certified professional.

Birchcliff works hard to maintain the safety and integrity of its facility and pipeline infrastructure. The Corporation's Asset Integrity staff manages its Pressure Equipment Integrity Program in compliance with the Alberta Boilers Safety Association (ABSA) requirements and its Pipeline Integrity Program in compliance with AER requirements. These programs are audited internally on an annual basis by a qualified professional and externally on a periodic basis by an independent auditor to evaluate their effectiveness and are updated based on the findings from such audits. The Corporation's Chief Inspector and pipeline Asset Integrity Group make use of databases and associated work tracking systems to ensure that all integrity tasks (inspections, pigging, etc.) are scheduled and completed according to the requirements set forth in the Corporation's programs.

As part of its fundamental values, the Corporation recognizes the importance of and its responsibility for environmental stewardship. The Corporation endeavors to maintain excellence in environmental reporting and response and to take proactive steps to eliminate or reduce its environmental impact. As an organization which strives for continuous improvement, Birchcliff continues to look for and develop new technology, systems and processes that will help improve efficiency, reduce its environmental footprint and create a safer work environment. For example, the Corporation utilizes multi-well pads in many of its drilling operations and recycles as much water from its completion operations as it can.

Environmental assessments are undertaken for new projects or when acquiring new properties or facilities in order to identify, assess and minimize environmental risks and operational exposures. The Corporation conducts audits of operations to confirm compliance with internal standards and to stimulate improvement in practices where needed. Documentation is maintained to support internal accountability and measure operational performance against recognized industry indicators to assist in achieving the objectives of the described policies and programs.

Community Programs

Fostering a strong relationship with the community and its stakeholders is as integral to the success of the Corporation's projects as obtaining the required regulatory approvals. The Corporation believes cooperative, sincere and responsive consultation efforts with stakeholders in the areas in which Birchcliff operates creates a solid foundation for its business. Birchcliff has an experienced team working with local stakeholders to learn their values and priorities and to resolve any issues or concerns that arise in the course of its field operations.

Birchcliff recognizes the role that communities play in its success and looks for opportunities to give back. The Corporation is a staunch supporter of the community and the business and educational initiatives of the indigenous communities who live in the areas where Birchcliff operates. Every year, the Corporation participates in a number of community support endeavours in the areas surrounding its field operations and in Calgary. In 2018, the Corporation contributed to a number of local community initiatives that help to elevate and enhance the quality of life at the local level, including minor hockey and other amateur sports, local schools, agricultural societies and fire departments. To date, Birchcliff has helped to raise over $1,000,000 for both STARS Air Ambulance in the Grande Prairie area and the United Way of Calgary. Each year, the Corporation also raises funds for the YWCA. Birchcliff makes an annual contribution to Home Front Calgary, a community-justice response team dedicated to helping families experiencing domestic violence. Through Birchcliff's support of Momentum, Calgarians living in poverty learn how to achieve a sustainable livelihood. The Corporation donates to the OneSight program and supports the Canadian Cancer Society daffodil campaign. The Corporation volunteers with Feed the Hungry, providing healthy meals in an atmosphere of dignity and respect. During the holiday season, Birchcliff employees "adopt" a number of families in need and donate gifts, food and decorations to help make the holidays special. The Corporation also fills backpacks with living essentials and gifts for the Mustard Seed and prepares sandwiches for the homeless for the Calgary Drop-In Centre.

Through these activities and numerous others, Birchcliff creates and maintains long-term, positive partnerships and relationships, while promoting employee engagement in the communities in which it operates.

Specialized Skill and Knowledge

The Corporation employs individuals with various professional skills and knowledge in the course of pursuing its business plan. In addition, various specialized consultants are available to assist the Corporation in areas where it believes it doesn't need full-time employees. These professional skills include, but are not limited to, geology, geophysics, engineering, financial and business skills, which are generally available in the industry. Drawing on significant experience in the oil and natural gas business, the Corporation believes that its management team has a demonstrated track record of bringing together all of the key components to a successful exploration and production company: strong technical skills; expertise in planning and financial controls; the ability to execute on business development opportunities; and capital markets expertise.

Employees

The following table sets forth the number of the Corporation's employees at December 31, 2018:

	Number of Employees
Head Office Employees	122
Field Employees	60

In addition, the Corporation hires skilled contractors to perform drilling operations, well completions and other field service operations. See "*Risk Factors – Other Risks – Reliance on Key Personnel*".

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

All of the Corporation's reserves are located in the Province of Alberta. Birchcliff retained two independent qualified reserves evaluators, Deloitte and McDaniel, to evaluate and prepare reports on 100% of Birchcliff's light crude oil and medium crude oil (combined), conventional natural gas, shale gas and NGLs reserves. Deloitte evaluated all of Birchcliff's properties other than the Corporation's properties in Gordondale, representing approximately 78% of the assigned total proved plus probable reserves. McDaniel evaluated the reserves attributable to the Corporation's properties in Gordondale, representing approximately 22% of the assigned total proved plus probable reserves.

The statement of reserves data and other oil and gas information set forth below is dated March 13, 2019. The effective date of the reserves and future net revenue information provided is December 31, 2018, unless otherwise indicated. The preparation date in respect of the reserves disclosure contained herein is February 13, 2019 and the preparation date in respect of the resource disclosure contained in Appendix A is March 13, 2019.

Supplemental disclosure of the Corporation's contingent resources data and prospective resources data has been included as Appendix A to this Annual Information Form. The Report on Reserves Data by Deloitte and McDaniel and the Report on Contingent Resources Data and Prospective Resources Data by Deloitte in Form 51-101F2 are attached to this Annual Information Form as Appendix B and the Report of Management and Directors on Oil and Gas Disclosure in Form 51-101F3 is attached to this Annual Information Form as Appendix C.

Disclosure of Reserves Data

The reserves data set forth below is based upon the evaluation by Deloitte with an effective date of December 31, 2018 as contained in the report of Deloitte dated February 13, 2019 (the "**Deloitte Reserves Report**") and the evaluation by McDaniel with an effective date of December 31, 2018 as contained in the report of McDaniel dated February 13, 2019 (the "**McDaniel Reserves Report**"), which are contained in the consolidated report of Deloitte dated February 13, 2019 with an effective date of December 31, 2018 (the "**Consolidated Reserves Report**"). Deloitte prepared the Consolidated Reserves Report by consolidating the properties evaluated by Deloitte in the Deloitte Reserves Report with the properties evaluated by McDaniel in the McDaniel Reserves Report, in each case using the Deloitte Price Forecast.

Deloitte and McDaniel have confirmed to the Reserves Evaluation Committee of the Board that their respective evaluations were prepared in accordance with the standards contained in the COGE Handbook and NI 51-101. In the course of preparing the reserves reports, Birchcliff provided Deloitte and McDaniel with basic information which included land, well and accounting (product prices and operating costs) information, reservoir and geological studies, estimates of on-stream dates for certain properties, contract information, budget forecasts and financial data. Other engineering, geological or economic data required to conduct the evaluations and upon which the reserves reports are based, were obtained from public records, other operators and from Deloitte's and McDaniel's non-confidential files. The extent and character of ownership and accuracy of all factual data supplied to Deloitte and McDaniel was accepted by each of Deloitte and McDaniel as presented. A field inspection and environmental/safety assessment of the properties that were the subject of the reserves evaluations was not conducted.

The net present value of future net revenue attributable to the Corporation's reserves is based on the Deloitte Price Forecast and is determined before provision for interest, debt servicing and general and administrative expense and after the deduction of royalties, operating costs, development costs and abandonment and reclamation costs.

The after-tax net present value of the Corporation's oil and natural gas properties reflects the income tax burden on the properties on a stand-alone basis and takes into account the Corporation's existing tax pools. It does not consider the business-entity-level tax situation or tax planning. It does not provide an estimate of the value at the level of the business entity, which may be significantly different. The Corporation's audited annual financial statements and related management's discussion and analysis for the year ended December 31, 2018 should be consulted for information at the level of the business entity.

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and NGLs reserves and the future net revenue attributed to such reserves. The reserves and associated future net revenue information set forth in this Annual Information Form are estimates only. In general, estimates of economically recoverable oil, natural gas and NGLs reserves and the future net revenue therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserves recovery, the timing and amount of capital expenditures, marketability of oil, natural gas and NGLs, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially from actual results. For these reasons, estimates of the economically recoverable oil, natural gas and NGLs reserves attributable to any particular group of properties, the classification of such reserves based on risk of recovery and estimates of future net revenue associated with reserves prepared by different engineers, or by the same engineer at different times, may vary. The Corporation's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material.

It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to the Corporation's reserves estimated by the Corporation's independent qualified reserves evaluators represent the fair market value of those reserves. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. The recovery and reserves estimates of Birchcliff's oil, natural gas and NGLs reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual oil, natural gas and NGLs reserves may be greater than or less than the estimates provided herein and variances could be material. Estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

NI 51-101 requires a reporting issuer to disclose its reserves in accordance with the product types contained in NI 51-101, which product types include conventional natural gas and shale gas. "Shale gas" as defined in NI 51-101 means natural gas: (i) contained in dense organic-rich rocks, including low-permeability shales, siltstones and carbonates, in which the natural gas is primarily adsorbed on the kerogen or clay minerals; and (ii) that usually requires the use of hydraulic fracturing to achieve economic production rates. With respect to Birchcliff's natural gas reserves attributable to its Montney/Doig Natural Gas Resource Play, such reserves would most closely fit within the category of shale gas as opposed to conventional natural gas. Birchcliff considers that its natural gas reserves attributable to the Montney/Doig Natural Gas Resource Play to be low permeability gas resources or "tight gas" (as such term is defined in the COGE Handbook). "Shale gas" is the NI 51-101 product type that most closely matches the natural gas from Birchcliff's Montney/Doig Natural Gas Resource Play.

As the tables below summarize the data contained in the Consolidated Reserves Report, they may contain slightly different numbers than the Consolidated Reserves Report due to rounding. Also due to rounding, certain columns may not add exactly.

The information relating to the Corporation's reserves contains forward-looking statements and information, including information relating to future net revenue, forecast capital expenditures, future development plans and costs related thereto, forecast operating costs, anticipated production and abandonment and reclamation costs. See *"Special Notes to Reader – Forward-Looking Statements"*.

For additional information, see *"Presentation of Oil and Gas Reserves and Resources", "Special Notes to Reader"* and *"Risk Factors – Business and Operational Risks – Uncertainty of Reserves and Resource Estimates"*.

Reserves Summary

The following table sets forth the Corporation's light crude oil and medium crude oil, conventional natural gas, shale gas and NGLs reserves at December 31, 2018, estimated using the Deloitte Price Forecast:

Summary of Reserves at December 31, 2018
(Forecast Prices and Costs)

	Light Crude Oil and Medium Crude Oil		Conventional Natural Gas		Shale Gas		NGLs		Total Boe	
Reserves Category	***Gross (Mbbls)***	***Net (Mbbls)***	***Gross (MMcf)***	***Net (MMcf)***	***Gross (MMcf)***	***Net (MMcf)***	***Gross (Mbbls)***	***Net (Mbbls)***	***Gross (Mboe)***	***Net (Mboe)***
Proved										
Developed Producing	9,292.8	7,406.5	5,620.7	5,176.5	989,197.3	918,413.6	28,535.1	22,404.8	203,631.0	183,743.1
Developed Non-Producing	0.0	0.5	666.1	645.3	31,301.6	29,130.5	317.5	239.6	5,645.4	5,202.7
Undeveloped	11,221.1	9,451.5	3,192.9	2,930.1	2,568,438.0	2,339,902.8	40,571.5	32,695.9	480,397.7	432,619.5
Total Proved	20,513.9	16,858.5	9,479.7	8,752.0	3,588,937.0	3,287,446.9	69,424.1	55,340.3	689,674.1	621,565.3
Probable	14,318.3	11,287.8	8,546.2	7,973.1	1,519,533.0	1,347,374.6	43,397.8	33,596.7	312,396.0	270,775.8
Total Proved Plus Probable	34,832.2	28,146.3	18,025.9	16,725.1	5,108,470.0	4,634,821.5	112,821.9	88,937.0	1,002,070.1	892,341.1

Net Present Values of Future Net Revenue

The following table sets forth the net present values of future net revenue attributable to Birchcliff's reserves at December 31, 2018, estimated using the Deloitte Price Forecast, before and after deducting future income tax expenses and calculated at various discount rates:

Summary of Net Present Values of Future Net Revenue at December 31, 2018[1]
(Forecast Prices and Costs)

	Before Income Taxes Discounted At (%/year)					
Reserves Category	**0** ***(MM$)***	**5** ***(MM$)***	**10** ***(MM$)***	**15** ***(MM$)***	**20** ***(MM$)***	**Unit Value Discounted at 10%/year** ***($/boe)***[1]
Proved						
Developed Producing	4,259.1	3,027.3	2,320.1	1,874.6	1,572.9	12.63
Developed Non-Producing	98.6	64.4	46.1	35.2	28.2	8.87
Undeveloped	8,155.5	4,217.5	2,342.1	1,341.1	761.3	5.41
Total Proved	12,513.2	7,309.1	4,708.3	3,250.9	2,362.4	7.57
Probable	6,869.4	2,898.5	1,433.1	789.6	469.2	5.29
Total Proved Plus Probable	19,382.6	10,207.6	6,141.4	4,040.5	2,831.6	6.88

(1) Unit values are based on net reserves.

	After Income Taxes Discounted At (%/year)[1]				
Reserves Category	**0** ***(MM$)***	**5** ***(MM$)***	**10** ***(MM$)***	**15** ***(MM$)***	**20** ***(MM$)***
Proved					
Developed Producing	3,661.6	2,675.6	2,097.8	1,726.4	1,470.0
Developed Non-Producing	72.0	47.5	34.5	26.8	21.8
Undeveloped	5,946.0	2,999.7	1,592.1	842.4	411.2
Total Proved	9,679.5	5,722.9	3,724.5	2,595.7	1,903.1
Probable	5,014.4	2,087.5	1,008.5	538.2	306.9
Total Proved Plus Probable	14,694.0	7,810.3	4,733.0	3,133.8	2,209.9

(1) The after-tax net present value of Birchcliff's oil and natural gas properties reflects the income tax burden on the properties on a stand-alone basis and takes into account Birchcliff's existing tax pools. It does not consider the business-entity-level tax situation or tax planning. It does not provide an estimate of the value at the level of the business entity, which may be significantly different. The Corporation's audited annual financial statements and related management's discussion and analysis for the year ended December 31, 2018 should be consulted for information at the level of the business entity.

Elements of Future Net Revenue

The following table sets forth the various elements of the Corporation's future net revenue attributable to the Corporation's reserves as estimated by Deloitte at December 31, 2018, estimated using the Deloitte Price Forecast and calculated without discount:

Elements of Future Net Revenue (Undiscounted) at December 31, 2018
(Forecast Prices and Costs)

Reserves Category	Revenue *(MM$)*	Royalties *(MM$)*	Operating Costs *(MM$)*	Develop-ment Costs *(MM$)*	Abandon-ment and Reclamat-ion Costs *(MM$)*	Future Net Revenue Before Future Income Tax Expenses *(MM$)*	Future Income Tax Expenses *(MM$)*	Future Net Revenue After Future Income Tax Expenses *(MM$)*[(1)]
Proved	22,163.4	2,561.1	3,941.1	2,961.8	186.2	12,513.2	2,833.7	9,679.5
Proved Plus Probable	34,883.6	4,448.9	6,496.6	4,291.8	263.7	19,382.6	4,688.6	14,694.0

(1) The after-tax net present value of Birchcliff's oil and natural gas properties reflects the income tax burden on the properties on a stand-alone basis and takes into account Birchcliff's existing tax pools. It does not consider the business-entity-level tax situation or tax planning. It does not provide an estimate of the value at the level of the business entity, which may be significantly different. The Corporation's audited annual financial statements and related management's discussion and analysis for the year ended December 31, 2018 should be consulted for information at the level of the business entity.

Net Present Values of Future Net Revenue by Product Type

The following table sets forth by product type the future net revenue associated with the Corporation's reserves at December 31, 2018, estimated using the Deloitte Price Forecast, before deducting future income tax expenses and calculated using a 10% discount rate:

Net Present Values of Future Net Revenue by Product Type at December 31, 2018
(Forecast Prices and Costs)

Reserves Category	Product Type	Future Net Revenue Before Income Taxes (Discounted at 10%/year) *(MM$)*	Unit Value Before Income Taxes (Discounted at 10%/year) *($/boe)*[(1)]
Proved	Light Crude Oil and Medium Crude Oil (including solution gas and other by-products)	861.7	10.95
	Conventional Natural Gas (including by-products but excluding solution gas and by-products from oil wells)	4.8	3.19
	Shale Gas (including by-products)	3,841.8	7.10
	Total	**4,708.3**	**7.57**
Proved Plus Probable	Light Crude Oil and Medium Crude Oil (including solution gas and other by-products)	1,391.9	10.03
	Conventional Natural Gas (including by-products but excluding solution gas and by-products from oil wells)	9.4	3.28
	Shale Gas (including by-products)	4,740.1	6.31
	Total	**6,141.4**	**6.88**

(1) Unit amounts are derived using net reserves volumes of the product type and associated by-products.

Pricing Assumptions

Forecast Prices Used in Estimates

The following table sets forth the forecast price and cost assumptions used in the Consolidated Reserves Report as contained in the Deloitte Price Forecast:

Deloitte Price Forecast

	Crude Oil		Natural Gas			NGLs					
Year	WTI at Cushing Oklahoma *(US$/bbl)*	Edmonton City Gate *(CDN$/bbl)*	Alberta AECO Average Price *(CDN$/Mcf)*[(1)]	Ontario Dawn Reference Point *(CDN$/Mcf)*[(1)]	NYMEX Henry Hub *(US$/Mcf)*[(1)]	Edmonton Ethane *(CDN$/bbl)*	Edmonton Propane *(CDN$/bbl)*	Edmonton Butane *(CDN$/bbl)*	Edmonton Pentanes + Condensate *(CDN$/bbl)*	Currency Exchange Rate *(CDN$/US$)*	Price and Cost Inflation Rates *(%)*
2019	58.00	65.80	1.75	3.90	3.00	5.70	32.90	29.60	75.65	0.760	0.0
2020	61.20	72.45	2.20	4.15	3.15	6.10	36.25	39.90	79.70	0.760	2.0
2021	64.50	78.35	2.50	4.40	3.45	6.95	39.15	50.95	86.20	0.770	2.0
2022	69.00	81.95	2.80	4.50	3.60	7.85	40.95	53.25	90.10	0.790	2.0
2023	75.75	89.30	3.20	4.75	3.85	8.95	44.65	58.05	98.25	0.800	2.0
2024	77.30	91.10	3.55	5.15	4.15	9.90	45.55	59.25	100.20	0.800	2.0
2025	78.85	92.90	3.85	5.45	4.40	10.70	46.45	60.40	102.20	0.800	2.0
2026	80.40	94.75	3.95	5.65	4.55	11.10	47.40	61.65	104.25	0.800	2.0
2027	82.00	96.65	4.10	5.80	4.70	11.50	48.35	62.85	106.35	0.800	2.0
2028	83.65	98.60	4.20	5.90	4.80	11.70	49.30	64.10	108.45	0.800	2.0
2029	85.35	100.55	4.25	6.05	4.90	11.95	50.30	65.40	110.60	0.800	2.0
2030	87.05	102.60	4.35	6.15	4.95	12.20	51.30	66.70	112.85	0.800	2.0
2031	88.80	104.65	4.45	6.30	5.05	12.45	52.30	68.05	115.10	0.800	2.0
2032	90.55	106.70	4.55	6.40	5.15	12.70	53.35	69.40	117.40	0.800	2.0
2033	92.35	108.85	4.60	6.55	5.30	12.95	54.45	70.80	119.75	0.800	2.0
2034	94.20	111.05	4.70	6.65	5.40	13.20	55.50	72.20	122.15	0.800	2.0
2035	96.10	113.25	4.80	6.80	5.50	13.45	56.65	73.65	124.60	0.800	2.0
2036	98.00	115.50	4.90	6.95	5.60	13.70	57.75	75.10	127.05	0.800	2.0
2037	100.00	117.85	5.00	7.05	5.70	14.00	58.90	76.65	129.60	0.800	2.0
2038	102.00	120.20	5.10	7.20	5.85	14.30	60.10	78.15	132.20	0.800	2.0
2038+	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	0.800	2.0

(1) 1 Mcf = 1 MMBtu.

The pricing and cost assumptions used were determined by Deloitte based on information available from numerous governmental agencies, industry publications, oil refineries, natural gas marketers and industry trends. These long-term price forecasts are subject to the many uncertainties that affect long-term future forecasts.

Weighted Average Commodity Prices

The Corporation's weighted average realized commodity prices for the year ended December 31, 2018, excluding the effects of financial hedges but including the effects of physical delivery contracts, were as follows:

- Light Crude Oil and Medium Crude Oil (Combined): $68.66/bbl.
- Shale Gas: $2.45/Mcf (includes conventional natural gas, which represented less than 1% of the Corporation's total corporate natural gas production during 2018).
- NGLs: $44.66/bbl.

Reconciliation of Changes in Reserves

The following table sets forth a reconciliation of the Corporation's gross reserves at December 31, 2018 as set forth in the Consolidated Reserves Report, estimated using the Deloitte Price Forecast, to the Corporation's gross reserves at December 31, 2017 as set forth in the Prior Consolidated Reserves Report, estimated using Deloitte's forecast price and cost assumptions effective December 31, 2017:

Reconciliation of Gross Reserves from December 31, 2017 to December 31, 2018
(Forecast Prices and Costs)

Factors	**Light Crude Oil and Medium Crude Oil** *(Mbbls)*	**Conventional Natural Gas** *(MMcf)*	**Shale Gas** *(MMcf)*	**NGLs** *(Mbbls)*	**Oil Equivalent** *(Mboe)*
GROSS TOTAL PROVED					
Opening balance December 31, 2017	**16,615.8**	**21,752.4**	**3,470,382.2**	**65,842.3**	**664,480.5**
Discoveries(1)	0.0	0.0	0.0	0.0	0.0
Extensions & Improved Recovery(2)	2,304.6	0.0	167,870.6	2,950.3	33,233.3
Technical Revisions(3)	3,436.2	(4,081.1)	82,830.1	4,322.0	20,883.0
Acquisitions(4)	0.0	15.9	2,722.3	37.7	494.1
Dispositions(5)	(235.3)	(4,941.9)	0.0	(11.9)	(1,070.8)
Economic Factors(6)	171.2	(2,416.2)	124.3	4.8	(206.0)
Production(7)	(1,778.6)	(849.4)	(134,992.5)	(3,721.1)	(28,140.0)
Closing balance December 31, 2018	**20,513.9**	**9,479.7**	**3,588,937.0**	**69,424.1**	**689,674.1**
GROSS TOTAL PROBABLE					
Opening balance December 31, 2017	**14,394.0**	**14,103.2**	**1,449,379.3**	**49,727.2**	**308,034.8**
Discoveries(1)	0.0	0.0	0.0	0.0	0.0
Extensions & Improved Recovery(2)	1,280.5	0.0	28,582.0	885.6	6,929.8
Technical Revisions(3)	(1,094.9)	(4,924.4)	16,047.0	(8,214.5)	(7,455.7)
Acquisitions(4)	0.0	0.0	24,954.9	969.3	5,128.4
Dispositions(5)	(264.3)	(2,210.4)	0.0	(6.6)	(639.2)
Economic Factors(6)	3.0	1,577.8	569.9	36.8	397.8
Production(7)	0.0	0.0	0.0	0.0	0.0
Closing balance December 31, 2018	**14,318.3**	**8,546.2**	**1,519,533.0**	**43,397.8**	**312,396.0**
GROSS TOTAL PROVED PLUS PROBABLE					
Opening balance December 31, 2017	**31,009.7**	**35,855.6**	**4,919,761.5**	**115,569.4**	**972,515.3**
Discoveries(1)	0.0	0.0	0.0	0.0	0.0
Extensions & Improved Recovery(2)	3,585.1	0.0	196,452.5	3,835.9	40,163.1
Technical Revisions(3)	2,341.3	(9,005.5)	98,877.1	(3,892.5)	13,427.5
Acquisitions(4)	0.0	15.9	27,677.2	1,007.0	5,622.5
Dispositions(5)	(499.5)	(7,152.4)	0.0	(18.5)	(1,710.0)
Economic Factors(6)	174.2	(838.4)	694.2	41.6	191.8
Production(7)	(1,778.6)	(849.4)	(134,992.5)	(3,721.1)	(28,140.0)
Closing balance December 31, 2018	**34,832.2**	**18,025.9**	**5,108,470.0**	**112,821.9**	**1,002,070.1**

(1) Additions to volumes in reservoirs where no reserves were previously booked.

(2) Additions to volumes resulting from capital expenditures for: (i) step-out drilling in previously discovered reservoirs; (ii) infill drilling in previously discovered reservoirs that were not drilled as part of an enhanced recovery scheme; and (iii) the installation of improved recovery schemes.

(3) Positive or negative volume revisions to an estimate resulting from new technical data or revised interpretations on previously assigned volumes, performance and operating costs.

(4) Positive additions to volume estimates because of purchasing interests in oil and gas properties.

(5) Reductions in volume estimates because of selling all or a portion of an interest in oil and gas properties.

(6) Changes to volumes resulting from different price forecasts, inflation rates and regulatory changes.

(7) Reductions in the volume estimates due to production.

Key highlights include the following:

- Extensions and Improved Recovery – Reserves added were due to the Corporation's successful 2018 capital program for the wells drilled and brought on production, including the additional offsetting future drilling locations that were assigned.

- Technical Revisions – The positive technical revisions in the total proved and the total proved plus probable reserves categories were primarily the result of the following: (i) for shale gas, increased well performance in existing and future drilling locations in Pouce Coupe; (ii) for light and medium crude oil, the reclassification of drilling locations from shale gas to light and medium crude oil in Gordondale; and (iii) for NGLs, the successful C3+ extraction project at Phases V and VI of the Pouce Coupe Gas Plant. These positive technical revisions were offset by the loss of NGLs reserves due to the cancellation of the proposed Phase VII deep-cut expansion at the Pouce Coupe Gas Plant in connection with Birchcliff entering into the Gordondale Processing Arrangement, as well as the removal of the conventional natural gas reserves for the planned abandonment of a non-core facility.

  The negative technical revisions in the total probable reserves category were primarily the result of the loss of NGLs reserves due to the cancellation of Phase VII, the removal of the conventional natural gas reserves for the planned abandonment of the non-core facility and the adjustment in light and medium crude oil reserves for future infill drilling locations in Gordondale.

- Acquisitions – Changes were the result of various minor acquisitions Birchcliff completed in the Gordondale and Pouce Coupe areas in 2018.

- Dispositions – Changes were the result of various non-core dispositions Birchcliff completed in 2018.

- Economic Factors – The lower natural gas price forecast resulted in the reduction of conventional natural gas reserves in the proved reserves category as one future drilling location was not economic to develop and was reclassified into the probable reserves category. In addition, the economic limit caused the reduction of proved plus probable conventional natural gas reserves. This was offset by the slightly higher price forecasts for oil and NGLs which resulted in increases to the light and medium crude oil, shale gas and NGLs reserves in all reserves categories.

Additional Information Relating to Reserves Data

Undeveloped Reserves

Undeveloped reserves are attributed by Deloitte and McDaniel in accordance with standards and procedures contained in the COGE Handbook. Proved undeveloped reserves are those reserves that can be estimated with a high degree of certainty and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Probable undeveloped reserves are those reserves that are less certain to be recovered than proved reserves and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Proved and probable undeveloped reserves have been assigned in accordance with engineering and geological practices as defined under NI 51-101.

Approximately 100% of the Corporation's proved undeveloped reserves are attributed to the Montney/Doig Resource Play concentrated in the Corporation's key operating areas in Pouce Coupe and Gordondale. The Consolidated Reserves Report has attributed proved undeveloped reserves to each potential future horizontal drilling location that is proximal to an existing well to which Deloitte and McDaniel attributed proved developed reserves. Deloitte and McDaniel estimated such proved undeveloped reserves using forecast production rates that were based on a statistical analysis of production rates of existing wells operated by the Corporation or others on the Montney/Doig Resource Play in the regional area. If the development timeline went beyond five years of a major plant expansion, then these proximal locations were classified as probable undeveloped reserves.

The following table sets forth for each product type the volumes of each of the proved undeveloped reserves and the probable undeveloped reserves from the applicable reserves evaluations that were first attributed as reserves in each of the three most recent financial years:

Undeveloped Reserves

	Proved Undeveloped Reserves				**Probable Undeveloped Reserves**			
Year of first attribution	**Light Crude Oil and Medium Crude Oil *(Mbbls)***	**Conventional Natural Gas *(MMcf)***	**Shale Gas *(MMcf)***	**NGLs *(Mbbls)***	**Light Crude Oil and Medium Crude Oil *(Mbbls)***	**Conventional Natural Gas *(MMcf)***	**Shale Gas *(MMcf)***	**NGLs *(Mbbls)***
2018	4,909	0	161,072	10,345	3,742	0	147,460	7,084
2017	3,922	0	603,102	10,507	6,147	0	219,167	10,345
2016	8,921	633	578,861	18,275	10,091	1,860	628,657	26,426

The Corporation has a large inventory of development opportunities in its portfolio and its capital spending activities are prioritized to optimize development plans, achieve strategic goals and maximize shareholder value.

As at December 31, 2018, undeveloped reserves represented approximately 70% of the Corporation's total proved reserves and approximately 75% of the Corporation's total proved plus probable reserves. Birchcliff is focused on developing these undeveloped reserves in its core areas of Pouce Coupe and Gordondale where the vast majority of the undeveloped reserves are assigned and available processing capacity exists and future processing capacity expansions are forecast to take place. In the Consolidated Reserves Report, the Corporation's independent qualified reserves evaluators forecast that 27 net wells and 97 net wells would be drilled in 2019 and 2020, respectively. The Corporation's 2019 Capital Program contemplates the drilling of 17 (17.0 net) Montney/Doig horizontal wells during 2019 and the bringing on production of 26 (26.0 net) wells. Birchcliff anticipates that drilling activities in 2019 and 2020 will utilize available capacity at the Pouce Coupe Gas Plant (currently 340 MMcf/d) and the Gordondale Gas Plant (currently 120 MMcf/d), as well as capacity as it becomes available from third-party processors. Over the ensuing years, the Corporation expects that it will continue to develop its proved undeveloped reserves on the Montney/Doig Resource Play as processing capacity at the Pouce Coupe Gas Plant is forecast to be expanded to 660 MMcf/d.

Given the Corporation's large, contiguous and concentrated land base, significant inventory of potential future drilling locations, required timing of facility and infrastructure construction and the executional pace of the Corporation's drilling programs, the timing of the development of the Corporation's proved undeveloped and probable undeveloped reserves extends past two years. Approximately 23% of the proved undeveloped locations are forecast to be drilled within the first two years and approximately 4% of the probable undeveloped locations are forecast to be drilled within the first two years.

Undeveloped reserves are attributed by Deloitte and McDaniel in accordance with the standards and procedures contained in the COGE Handbook. As such, approximately 99.8% of the proved undeveloped locations are forecast to be drilled within a 7 year time frame as recommended by the COGE Handbook, which includes taking into account future development capital being deployed for construction of a processing facility expansion. Approximately 99.6% of the probable undeveloped locations are forecast to be drilled in a 10 year time frame as recommended by COGE Handbook for unconventional resource play development. The Corporation and its independent qualified reserves evaluators believe this to be a reasonable pace of development of these unconventional undeveloped reserves.

The pace of development of the Corporation's proved and probable undeveloped reserves is influenced by many factors, including the outcomes of the yearly drilling and reservoir evaluations, the price for oil and natural gas, and a variety of economic factors and conditions. There are a number of factors that could result in delayed or cancelled development, including the following: (i) changing economic conditions (due to pricing, operating and capital expenditure fluctuations); (ii) changing technical conditions (including production anomalies, such as water breakthrough or accelerated depletion); (iii) multi-zone developments (for instance, a prospective formation completion may be delayed until the initial completion is no longer economic); (iv) a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and (v) surface access issues (including those relating to land owners, weather conditions and regulatory approvals).

Significant Factors or Uncertainties Affecting Reserves Data

The process of estimating reserves is 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 reserves estimates contained in this Annual Information Form are based on current production forecasts, prices and economic conditions. Factors and assumptions that affect these reserves estimates include, but are not limited to, historical production from the properties, production rates, ultimate reserves recovery, the timing and amount of capital expenditures, marketability of oil, natural gas and NGLs, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially from actual results.

As circumstances change and additional data becomes available, reserves 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 governmental restrictions.

Although every reasonable effort is made to ensure that reserves estimates are accurate, reserves estimation is an inferential science. As a result, the subjective decisions, new geological or production information and a changing environment may impact these estimates. Revisions to reserves estimates can arise from changes in year-end oil and natural gas prices and reservoir performance. Such revisions can be either positive or negative.

Changes in future commodity prices relative to the forecasts described above under *''Pricing Assumptions''* could have a negative impact on the Corporation's reserves, and in particular on the development of undeveloped reserves, unless future development costs are adjusted in parallel. The Corporation has a significant amount of proved and probable undeveloped reserves. At the forecast prices and costs used in the Consolidated Reserves Report, these development activities are expected to be economic. However, should oil and natural gas prices decrease materially, these activities may not be economic and the Corporation may defer their implementation. This deferral could result in proved reserves being reclassified as probable reserves and probable reserves being reclassified as contingent resources. In addition, reserves can be significantly affected by fluctuations in product pricing, capital expenditures, operating costs, royalty regimes, abandonment and reclamation costs and well performance that is beyond the Corporation's control and which could affect the Corporation's development decisions.

Other than the foregoing and the factors disclosed or described herein, the Corporation does not anticipate any other significant economic factors or other significant uncertainties which may affect any particular components of its reserves data. See also *"Risk Factors – Business and Operational Risks – Uncertainty of Reserves and Resource Estimates"*.

Abandonment and Reclamation Costs

In connection with its operations, the Corporation will incur abandonment and reclamation costs for surface leases, wells, facilities and pipelines.

Abandonment and reclamation costs have been estimated by Deloitte and McDaniel in their respective evaluations, are attributed to all existing and future wells that were assigned reserves in their respective evaluations and do not include abandonment and reclamation costs for wells, facilities and pipelines to which no reserves were assigned. Well abandonment and reclamation costs used by Deloitte and McDaniel were not independently evaluated and were assumed to be equal to the average costs for the Corporation's regional reclamation cost area set forth in AER Directive 011: *Licensee Liability Rating (LLR) Program: Updated Industry Parameters and Liability Costs*.

As at December 31, 2018, the Corporation had 1,220.9 net wells to which proved plus probable reserves were attributed in the Consolidated Reserves Report for which the Corporation expects to incur abandonment and reclamation costs. In estimating the future net revenue disclosed in this Annual Information Form, the Consolidated Reserves Report deducted $263.7 million (undiscounted) and $12.5 million (10% discount) for abandonment and reclamation costs for all wells that have been attributed proved and probable reserves. There are no unusually significant abandonment and reclamation costs associated with the Corporation's properties to which reserves have been attributed.

The Corporation budgets for and recognizes as a liability the estimated present value of the future decommissioning liabilities associated with its oil and natural gas properties and equipment, including wells sites, processing facilities and gathering systems. Abandonment and reclamation costs for wells, facilities and pipelines to which no reserves were assigned were considered by the Corporation in its calculation of decommissioning liabilities. See Note 8 – *Decommissioning Obligations* to the Corporation's audited annual financial statements for the year ended December 31, 2018 and *"Description of the Business – Environmental Protection – Environmental Costs and Decommissioning Obligations".*

Future Development Costs

Future development costs reflect the independent reserves evaluator's best estimate of what it will cost to bring the proved and proved plus probable reserves on production. Changes in forecast future development costs occur annually as a result of development activities, acquisition and disposition activities and capital cost estimates. The following table sets forth development costs deducted in the estimation of the Corporation's future net revenue attributable to the reserves categories noted below:

Future Development Costs
(Forecast Prices and Costs)

	Proved *(MM$)*	**Proved Plus Probable** *(MM$)*
2019	244.9	271.0
2020	492.5	514.5
2021	399.6	506.4
2022	720.5	791.8
2023	477.0	535.0
Thereafter	627.3	1,673.1
Total undiscounted	**2,961.8**	**4,291.8**

The Corporation expects to be able to fund the development costs required in the future primarily from internally generated cash flows, as well as its existing credit facilities. Future development costs may also be funded through the proceeds realized from property dispositions and debt or equity financings. Planned activity levels vary each year due to factors such as capital availability, commodity prices, processing and transportation capacity and regulatory processes.

There can be no guarantee that funds will be available or that the Corporation will allocate funding to develop all of the reserves attributed in the Consolidated Reserves Report. Failure to develop those reserves would have a negative impact on the future production and future net revenue estimated by the Corporation's independent qualified reserves evaluators and could result in negative revisions to reserves.

Interest and other costs of external funding are not included in the estimates of reserves and future net revenue set forth herein and would reduce the reserves and future net revenue to some degree depending upon the funding sources utilized. The Corporation currently does not anticipate that interest or other funding costs would make the development of any of these properties uneconomic.

Other Oil and Gas Information

Oil and Gas Properties and Wells

The Corporation's important properties and facilities are described under the heading *"Description of the Business".* All of the Corporation's properties are located in Alberta and are onshore. None of the Corporation's important properties or facilities are subject to any material statutory or other mandatory relinquishments, surrenders, back-ins or changes in ownership.

The following table sets forth the Corporation's producing and non-producing oil and natural gas wells at December 31, 2018:

Producing and Non-Producing Wells at December 31, 2018[(1)]

	Oil Wells				Natural Gas Wells			
	Producing		Non-producing		Producing		Non-producing	
	Gross	***Net***	***Gross***	***Net***	***Gross***	***Net***	***Gross***	***Net***
Alberta	119	99.9	35	18.1	412	384.2	167	118.3

(1) Does not include water injection wells, service wells, capped wells and wells that have not been categorized as either oil wells or natural gas wells.

The Corporation has no properties to which reserves have been attributed which are capable of production but not producing except as described herein. At December 31, 2018, the Corporation had 9 (6.2 net) wells categorized as proved non-producing in the Consolidated Reserves Report. These wells have been non-producing for periods ranging from five months to eight years. All of these wells are near pipelines and processing facilities and consist of vertical and horizontal wells. Birchcliff expects 8 of these wells to be classified as proved developed producing at the end of 2019. Currently 2 of the 9 wells are back on production. Of the remaining 7 wells, 6 are expected to be brought on production later in 2019. The remaining well, in which Birchcliff only has a working interest of 1.875%, has been shut-in for eight years. The well requires re-activation capital and the Corporation expects this to be completed by the operator in 2020.

Undeveloped Lands

The following table sets forth the gross and net acres of undeveloped lands held by the Corporation as at December 31, 2018:

Undeveloped Lands

	Gross Acres	Net Acres
Alberta	200,789.4	178,296.7

When determining gross and net acreage for two or more leases covering the same lands but different rights, the acreage is reported for each lease. When there are multiple discontinuous rights in a single lease, the acreage is reported only once.

The rights to explore, develop and exploit with respect to 45,600.0 (43,104.0 net) acres of such undeveloped lands are expected to expire within one year of the date of this Annual Information Form. Such expiries will not materially affect the reserves attributable to Birchcliff's lands. The Corporation has no material work commitments on such undeveloped lands.

Significant Factors or Uncertainties Relevant to Properties with No Attributed Reserves

There are several economic factors and significant uncertainties that affect the anticipated development of the Corporation's properties to which no reserves have been attributed. The Corporation will be required to make substantial capital expenditures in order to prove, exploit, develop and produce oil and natural gas from these properties in the future. If the Corporation's cash flow from operations is not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or, if available, that the terms will be acceptable to the Corporation. Failure to obtain such financing on a timely basis could cause the Corporation to forfeit its interest in certain properties, miss certain opportunities, reduce its pace of development or terminate its operations on such properties. An inability of the Corporation to access sufficient capital for its exploration and development purposes could have a material adverse effect on the Corporation's ability to execute its business strategy to develop its prospects.

The significant economic factors that affect the Corporation's future development of its lands to which no reserves have been attributed are:

(i) future commodity prices for oil and natural gas (and the Corporation's outlook relating to such prices);

(ii) the future capital costs of drilling, completing, tying in and equipping the wells necessary to develop such lands at the relevant times;

(iii) the future costs of operating wells at the relevant times; and

(iv) the levels of royalties applicable to productions from such lands.

The significant uncertainties that affect the Corporation's development of its lands to which no reserves have been attributed are:

(i) the ability of the Corporation to obtain the capital necessary to fund the development of such lands at the relevant times;

(ii) the future drilling and completion results the Corporation achieves in its development activities (e.g. with respect to the development of particular intervals or geographic areas, the uncertainty would be whether the initial drilling and completion results are sufficient to justify the development of such interval or geographic area);

(iii) drilling and completion results achieved by others on lands in proximity to the Corporation's lands;

(iv) transportation and processing infrastructure becoming available in a timeline consistent with proposed development plans;

(v) the availability of regulatory approvals for development of the lands and the necessary infrastructure; and

(vi) governmental actions and future changes to applicable regulatory or royalty regimes that affect timing or economics of proposed development activities.

All of these uncertainties have the potential to delay the development of such lands. On the other hand, uncertainty as to the timing and nature of the evolution of better exploration, drilling, completion and production technologies have the potential to accelerate development activities and enhance the economics relating to the development of such lands.

There are no unusually significant abandonment and reclamation costs associated with the Corporation's properties to which no reserves have been attributed.

For a description of the Corporation's contingent and prospective resources, including a discussion of the development plans for the Corporation's development pending contingent resource projects and the contingencies which prevent the Corporation's contingent resources from being classified as reserves, see Appendix A to this Annual Information Form. See also "*Risk Factors*".

Forward Contracts and Transportation and Processing Obligations

The Corporation has used and may continue to use various types of derivative financial instruments and physical delivery contracts to manage the risks related to fluctuating commodity prices. Subject to compliance with the Credit Facilities, the Board has authorized the Corporation to execute a risk management strategy whereby Birchcliff is authorized to enter into agreements and financial or physical transactions with one or more counterparties from time to time that are intended to protect the Corporation from volatility in future commodity prices, foreign exchange rates and/or interest rates. A summary of the Corporation's commodity price risk management contracts can be found in Note 18 – *Financial Risk Management* to the Corporation's audited annual financial statements for the year ended December 31, 2018 and under the heading *"Commodity Price Risk Management Contracts"* in the Corporation's management's discussion and analysis for the year ended December 31, 2018. Other than as disclosed in the Corporation's audited annual financial statements for the year ended December 31, 2018, the Corporation is not bound by any agreement (including any transportation agreement), directly or through an aggregator, under which it is precluded from fully realizing, or may be protected from the full effect of, future market prices for crude oil or natural gas. See *''Risk Factors''* for additional information on the risks and uncertainties relating to the Corporation's hedging activities.

As part of normal business operations, the Corporation enters into firm-service obligations for the transportation and processing (as applicable) of its natural gas, oil and NGLs production volumes in order to secure access to the infrastructure necessary to transport and process such volumes. Accordingly, the Corporation renews, amends or enters into new firm-service agreements from time to time, having consideration for its forecast capacity requirements and current and future growth plans, capacity constraints and its expectations for future transportation and processing costs.

With respect to transportation, the Corporation believes that to move its production to market over the short and long-term, it should generally secure firm transportation sufficient for its current and future growth plans. The Corporation has transportation commitments that exceed forecast production volumes of the Corporation's proved reserves in the Consolidated Reserves Report for the period from January 1, 2019 to December 31, 2021 by an average of approximately 65.2 MMcf/d. These excess commitments relate to the Corporation's firm service commitments on the NGTL System (see *"Description of the Business – Transportation Arrangements"*). The estimated cost of the excess transportation equates to an undiscounted total cost of approximately $20 million over the period (2019: $8.5 million; 2020: $6.0 million; 2021: $5.5 million). Birchcliff strives to mitigate excess NGTL transportation costs through marketing initiatives to other parties that do not have firm transportation to move natural gas volumes on the NGTL System.

With respect to processing, the Corporation has fractionation processing commitments that exceed forecast production volumes of the Corporation's proved reserves in the Consolidated Reserves Report for the period from January 1, 2019 to March 31, 2026 by an average of 2,300 bbls/d. These excess commitments relate to the Corporation's fractionation commitments for NGLs at the Pembina Facility (see *"Description of the Business – Processing Arrangements"*). The estimated cost of the excess fractionation equates to an undiscounted total cost of approximately $20 million over the period. Birchcliff strives to mitigate excess NGLs fractionation costs through strategic marketing with third parties and other producers that are short fractionation capacity.

Tax Horizon

The Corporation was not required to pay any cash income taxes for the year ended December 31, 2018. The Corporation estimates that based on its current expenditure plans and the current price environment, no income taxes will become payable on the Corporation's income for the financial year ended December 31, 2019. As at December 31, 2018, the Corporation had accumulated tax pools and loss carry forwards of approximately $2.1 billion which can be used to offset taxable income in future years. Based on anticipated capital investment, which further augments the tax pools, it is likely that the Corporation will not become taxable within the next five years as long as commodity prices remain consistent with today's environment.

Costs Incurred

The following table sets forth the Corporation's property acquisition costs for proved and unproved properties, exploration costs and development costs for the year ended December 31, 2018:

2018 Acquisition, Exploration and Development Costs

Acquisition Costs			
Proved Properties ***(MM$)***	**Unproved Properties** ***(MM$)***	**Exploration Costs** ***(MM$)***	**Development Costs** ***(MM$)***
1.5	0.0	10.7	289.0

Exploration and Development Activities

The following table sets forth the gross and net exploratory and development wells that the Corporation participated in during the year ended December 31, 2018:

2018 Exploration and Development Activities

	Exploratory Wells(1)		Development Wells(1)		Total(1)	
	Gross	***Net***	***Gross***	***Net***	***Gross***	***Net***
Oil Wells	0.0	0.0	17.0	17.0	17.0	17.0
Natural Gas Wells	0.0	0.0	19.0	19.0	19.0	19.0
Service Wells	0.0	0.0	0.0	0.0	0.0	0.0
Stratigraphic Test Wells	0.0	0.0	0.0	0.0	0.0	0.0
Dry Holes	0.0	0.0	0.0	0.0	0.0	0.0
Total	**0.0**	**0.0**	**36.0**	**36.0**	**36.0**	**36.0**

(1) Number of wells based on rig release dates.

The Corporation's most important current and likely exploration and development activities for 2019 will focus on the drilling of wells on the Montney/Doig Resource Play, as well as increasing the inlet liquids-handling capacity at the Pouce Coupe Gas Plant and funding other infrastructure enhancement projects for future growth. The 2019 Capital Program contemplates the drilling of 17 (17.0 net) wells (9 in Pouce Coupe and 8 in Gordondale) and the bringing on production of 26 (26.0 net) wells in 2019. See *"General Development of the Business – Recent Developments"* for further information regarding the Corporation's capital spending plans for 2019.

Production Estimates

The following table sets forth the volume of production estimated for the year ending December 31, 2019 which is reflected in the estimates of gross proved reserves and gross probable reserves disclosed in the tables above under the heading *"Statement of Reserves Data and Other Oil and Gas Information – Disclosure of Reserves Data"*:

2019 Production Volume Estimates

	Light Crude Oil and Medium Crude Oil *(Mbbls)*	Shale Gas *(MMcf)*(1)	NGLs *(Mbbls)*	Oil Equivalent *(Mboe)*
Gross Proved	1,936	140,534	4,230	29,588
Gross Probable	61	4,248	140	909

(1) Conventional natural gas volumes have been included in the shale gas volumes as conventional natural gas volumes represented less than 1% of the volume estimates for 2019.

The following table sets forth the estimated production volumes for the fields that account for more than 20% of the estimated production volumes for the year ending December 31, 2019:

2019 Production Volume Estimates for Important Fields

Field Name	**Gross Proved Reserves** ***(Mboe)***	**Gross Probable Reserves** ***(Mboe)***
Pouce Coupe	18,468	681
Gordondale	11,028	231

Production History

The following table sets forth, by product type, the average daily production, the average prices received, the royalties paid, the production costs incurred, the transportation and other costs incurred and the resulting netback for the periods indicated:

2018 Average Daily Production, Prices Received, Royalties, Costs and Resulting Netback

	Three months ended				Year ended
	March 31, 2018	**June 30, 2018**	**September 30, 2018**	**December 31, 2018**	**December 31, 2018**
Average Daily Production[1]					
Light Crude Oil and Medium Crude Oil *(bbls/d)*	4,136	5,599	4,959	4,788	4,873
Shale Gas *(Mcf/d)*[2]	377,473	364,360	383,279	363,596	372,170
NGLs *(bbls/d)*	9,274	9,970	10,492	11,021	10,195
Combined *(boe/d)*	76,323	76,296	79,331	76,408	77,096
Average Prices Received[3]					
Light Crude Oil and Medium Crude Oil *($/bbl)*	71.92	79.55	80.16	41.39	68.66
Shale Gas *($/Mcf)*[2]	2.72	2.01	2.06	3.03	2.45
NGLs *($/bbl)*	48.09	47.81	49.17	34.73	44.66
Combined *($/boe)*	23.22	21.69	21.46	22.01	22.08
Royalties Paid					
Light Crude Oil and Medium Crude Oil *($/bbl)*	15.70	12.59	13.50	6.46	11.96
Shale Gas *($/Mcf)*[2][4]	(0.02)	(0.03)	(0.02)	(0.03)	(0.03)
NGLs *($/bbl)*	5.56	5.91	5.72	4.95	5.52
Combined *($/boe)*	1.43	1.53	1.52	0.96	1.36
Production Costs					
Light Crude Oil and Medium Crude Oil *($/bbl)*	5.82	5.19	6.05	5.59	5.65
Shale Gas *($/Mcf)*[2]	0.58	0.50	0.50	0.53	0.53
NGLs *($/bbl)*	4.98	4.36	4.81	4.54	4.67
Combined *($/boe)*	3.78	3.36	3.45	3.51	3.52
Transportation and Other Costs					
Light Crude Oil and Medium Crude Oil *($/bbl)*	3.75	3.46	3.71	4.13	3.75
Shale Gas *($/Mcf)*[2]	0.54	0.58	0.56	0.65	0.58
NGLs *($/bbl)*	5.35	4.76	4.32	4.85	4.80
Combined *($/boe)*	3.56	3.64	3.46	4.07	3.68
Resulting Netback[5]					
Light Crude Oil and Medium Crude Oil *($/bbl)*	46.65	58.31	56.90	25.21	47.30
Shale Gas *($/Mcf)*[2]	1.62	0.96	1.02	1.88	1.37
NGLs *($/bbl)*	32.20	32.78	34.32	20.39	29.67
Combined *($/boe)*	14.45	13.16	13.03	13.47	13.52

(1) Before deduction of royalties and without including any royalty interests.

(2) Conventional natural gas volumes have been included in the shale gas volumes as conventional natural gas volumes represented less than 1% of the Corporation's total corporate natural gas production in 2018 and are therefore not considered material.

(3) Excludes the effects of hedges using financial instruments but includes the effects of physical delivery contracts.

(4) Includes the effects of prior period gas cost allowance credits received by the Corporation.

(5) Netback does not have any standardized meaning and should not be used for the purposes of drawing comparisons between the Corporation and other companies. For additional information regarding netbacks, see *"Non-GAAP Measures"* in the Corporation's management's discussion and analysis for the year ended December 31, 2018.

The following table sets forth, by product type, the Corporation's average daily production volumes for the year ended December 31, 2018 for each field comprising more than 10% of the Corporation's total production:

2018 Production Volumes By Field

	Light Crude Oil and Medium Crude Oil *(bbls/d)*	**Shale Gas** *(Mcf/d)*[(1)]	**NGLs** *(bbls/d)*	**Oil Equivalent** *(boe/d)*
Pouce Coupe	9	276,004	2,933	48,943
Gordondale	4,852	95,508	7,258	28,028

(1) Conventional natural gas volumes have been included in the shale gas volumes as conventional natural gas volumes represented less than 1% of the Corporation's total corporate natural gas production in 2018 and are therefore not considered material.

INDUSTRY CONDITIONS

Companies carrying on business in the oil and natural gas sector in Canada are subject to extensive controls and regulations imposed through the legislation of the Federal Government and the provincial governments where such companies have assets or operations. While these regulations and controls 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 controls and regulations carefully. Although governmental legislation is a matter of public record, the Corporation is unable to predict what additional legislation or amendments to existing legislation governments may enact in the future.

The Corporation holds interests in oil and natural gas properties, along with related assets, in the Province of Alberta. 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 oil and natural gas business include all manner of activities associated with the exploration for and production of 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) the storage, injection and disposal of substances associated with production operations; and (vii) the abandonment and reclamation of impacted sites. In order to conduct oil and natural gas operations and remain in good standing with Alberta's regulatory scheme, the Corporation 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 oil and natural gas industry in Western Canada, and particularly in the Province of Alberta.

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

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

NGLs

The price of condensate 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 price depends, in part, on the quality of the NGLs, price of competing chemical stock, distance to market, access to downstream transportation, supply/demand balance, the length of the contract term and other contractual terms.

Exports from Canada

Crude oil, natural gas and NGLs exports from Canada are subject to the NEB Act and the Part VI Regulations. The NEB Act and the Part VI Regulations 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 NEB is required. With respect to the export of natural gas and NGLs, a public hearing is not required. 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 natural 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 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 Regulations 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 20 years for quantities not exceeding 30,000 cubic metres 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. Currently, 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: *An Act to enact the Impact Assessment Act and the Canadian Energy Regulator Act, to amend the Navigation Protection Act and to make consequential amendments to other acts* ("**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 the export of crude oil, natural gas and NGLs from Canada will substantively change under the new regime as currently drafted. See *"Industry Conditions – Regulatory Authorities and Environmental Regulation – Federal".*

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 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, the 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 has 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 at 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 oil and natural gas industry has experienced significant difficulty expanding the existing network of transportation infrastructure for 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.

Natural gas prices in Alberta 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 possibly 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 (and 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 LNG 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.

The following sets forth the current state of certain projects, legislation and other developments that are relevant to the transportation and exportation of oil and natural gas from Western Canada to domestic and international markets:

- Enbridge Line 3 Expansion from Hardisty, Alberta, to Superior, Wisconsin: This pipeline has an expected in-service date in the latter half of 2020.

- Trans Mountain Pipeline expansion: The proposed 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 of Kinder Morgan Cochin ULC subsequently voted to approve the transaction in August 2018. However, the 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, Cabinet ordered the NEB to reconsider its recommendation in light of the Federal Court of Appeal decision, including the environmental effects of project-related marine shipping. On February 22, 2019, the NEB delivered an updated report to Cabinet, recommending that Cabinet approve the pipeline expansion, subject to 156 conditions and 16 new recommendations, notwithstanding the fact that project-related marine shipping may have a significant adverse effect on the marine environment. While Cabinet has three months to consider the NEB's report, it may extend this deadline to accommodate a new round of indigenous consultation, upon completion of which it will decide whether it will approve or deny the pipeline expansion.

- Keystone XL Pipeline: 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.

- Bill C-48: *Oil Tanker Moratorium Act – An Act respecting the regulation of vessels that transport crude oil or persistent oil to or from ports or marine installations located along British Columbia's north coast* ("**Bill C-48**"): 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"*.

- Government of Alberta Initiatives: The Government of Alberta has sought to alleviate transportation constraints by pursuing different transportation modalities and creating new markets. On November 28, 2018, the Government of Alberta announced that Alberta had started negotiations for investment in new rail capacity to address the historically high price differential. On February 19, 2019, the Government of Alberta announced that it would lease 4,400 rail cars capable of transporting 120,000 bbls/d of crude oil out of the province. The Alberta Petroleum Marketing Commission will purchase crude oil from producers and market it, using the expanded rail capacity to transport the marketed oil to purchasers. The Government expects the first railcars to be in service by July 2019 and believes this strategy will: (i) narrow the crude oil price gap by up to $4/bbl; and (ii) provide junior producers with a more affordable option to move their crude oil to market.

  In addition, on December 11, 2018, the Government of Alberta announced a Request for Expressions of Interest to create new refining capacity or expand existing capacity. Little is known about this strategy, but the deadline for interested parties to submit Expressions of Interest was February 8, 2019, and an internal governmental committee is currently reviewing such submissions.

- LNG Canada Export Terminal: In October 2018, the proponents of the LNG Canada LNG 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 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 MMbbls/d, a reduction of approximately 8.7% of total daily average 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 MMbbls/d. The Corporation is not subject to a curtailment order.

NAFTA and Other Trade Agreements

NAFTA 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, Prime Minister Justin Trudeau, U.S. President Donald Trump 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**"). NAFTA, however, remains the North American trade agreement currently in force until the legislative bodies of the three signatory countries ratify 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 ratified version of 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, in December 2018 the Government of Alberta announced a 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 oil and bitumen produced to the other NAFTA signatories. As a result of the proportionality rule, reducing Canadian supply reduces the required offering under NAFTA, with the result that the amount of crude oil and bitumen that Canada is required to offer, while Canadian crude oil is at depressed prices, may be reduced. It is not clear whether USMCA will come into force before the Government of Alberta's curtailment order is repealed automatically on December 31, 2019.

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, 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 have agreed to the Comprehensive Economic and Trade Agreement ("**CETA**"), which provides for duty-free, quota-free market access for Canadian oil and 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 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 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 oil and natural gas located in Western Canada. According to Alberta Energy, the Crown owns approximately 81% of the Province of Alberta's mineral rights. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences and permits for varying terms and on conditions set forth in provincial legislation, including requirements to perform specific work or make payments. The provincial governments in Western Canada's provinces conduct regular land sales where oil and natural gas companies bid for leases to explore for and produce 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.

The Province of Alberta has 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. In addition, the Province of Alberta has shallow rights reversion for shallow, non-productive geological formations for new leases and licences.

To develop oil and natural gas resources, it is necessary for the mineral rights holder 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.

In addition to Crown ownership of the rights to oil and natural gas, private ownership of oil and natural gas (i.e. freehold mineral lands) also exists in Alberta. According to Alberta Energy, approximately 19% of the mineral rights in Alberta are owned by private freehold owners and other non-Crown entities, as well as the Federal Government as discussed in further detail below. The rights to explore for and produce oil and natural gas with private freehold owners 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 oil and natural gas explorers and producers.

An additional category of mineral rights ownership includes ownership by the 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 the exploration and production of oil and natural gas on indigenous reservations.

Royalties and Incentives

General

Each province has legislation and regulations that govern royalties and production rates. The royalty regime in a given province is a significant factor in the profitability of 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 freehold mineral 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 Crown 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 the Western Canadian 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 the recovery of oil, natural gas and NGLs.

In addition, the Federal Government may from time to time provide incentives to the oil and natural gas industry. In November 2018, the Federal Government announced its plans to implement an accelerated investment incentive, which will provide oil and natural gas businesses with eligible Canadian development expenses and Canadian oil and natural 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 oil and natural gas projects related to economic diversification as well as direct funding for clean growth oil and natural gas projects.

Producers and working interest owners of 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.

The Royalty Framework in Alberta

Crown Royalties

In Alberta, the provincial government royalty rates apply to Crown-owned mineral rights. In 2016, the Government of 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 "**Previous 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 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 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 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 Previous 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, to 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 Previous Framework is applicable to all conventional oil and natural gas wells drilled prior to January 1, 2017. Subject to certain available incentives, effective from the January 2011 production month, royalty rates for conventional oil production under the Previous 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 Previous Framework range from a base rate of 5% to a cap of 36%. The Previous 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 Previous Framework, the royalty rate applicable to NGLs is a flat rate of 40% for pentanes and 30% for butanes and propane.

Freehold and Other Types of Non-Crown Royalties

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

IOGC is responsible for managing and regulating the oil and natural gas resources located on indigenous reservations across Canada. IOGC's responsibilities include negotiating and issuing the oil and natural gas agreements between indigenous groups and 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 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.

Incentives

The Government of Alberta has from time to time implemented drilling credits, incentives or transitional royalty programs to encourage 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.

Rental Payments and Freehold Mineral Taxes

Currently, producers of oil and natural gas from Crown lands in Alberta are required to pay annual rental payments, at a rate of $3.50 per hectare, in addition to the monthly royalty payments in respect of oil and natural gas produced.

In addition to the royalties payable to the mineral owners (or to other royalty holders, if applicable), producers of 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 oil and natural gas production from lands where the Crown does not hold the mineral rights. 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.

Regulatory Authorities and Environmental Regulation

General

The Canadian 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 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 GHG emissions, may impose further requirements on operators and other companies in the 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. 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 Government of Canada launched a review of the current environmental and regulatory processes. On February 8, 2018, the Government of Canada introduced Bill C-69 to overhaul the existing environmental assessment process in Canada and replace the NEB with a new regulator, the CER. Pursuant to the draft legislation, the Impact Assessment Agency of Canada (the "**IAA**") would replace the Canadian Environmental Assessment Agency. The revamped approval process for applicable major developments will have specific legislated timelines at each stage of the formal impact assessment process. The IAA's process would focus on: (i) early engagement by the proponents of projects with the IAA and all stakeholders (such as the public and indigenous groups) prior to the formal impact assessment process; (ii) potentially increased public participation where the project undergoes a panel review; (iii) providing analysis of the potential impacts and effects of a project without making recommendations, to support a public-interest approach to decision-making, with cost-benefit determinations and approvals made by the Minister of Environment and Climate Change or the Cabinet; (iv) analyzing further specified factors for projects such as alternatives to the project and social and indigenous issues in addition to health, environmental and economic impacts; and (v) overseeing an expanded follow-up, monitoring and enforcement process with increased involvement of indigenous peoples and communities. As to the proposed CER, many of its activities would be similar to the NEB, albeit with a different structure and with the notable exception that the CER would no longer have primary responsibility in the consideration of new major projects, instead focusing on the lifecycle regulation (e.g. overseeing construction, tolls and tariffs, operations and eventual winding down) of approved projects, while providing for expanded participation by communities and indigenous peoples. It is unclear when the new regulatory scheme will come into force or whether any amendments will be made prior to coming into force. Until then, the Government of Canada's interim principles released on January 27, 2016 will continue to guide decision-making authorities for projects currently undergoing environmental assessment. The eventual effects of the proposed regulatory scheme on the proponents of major projects remain unclear.

On May 12, 2017, the Government of Canada introduced Bill C-48. This legislation is aimed at providing coastal protection in northern British Columbia by prohibiting crude oil tankers carrying more than 12,500 metric tonnes of crude oil or persistent crude oil products from stopping, loading, or unloading crude oil in that area. Parliament is still considering the bill, which passed the second reading on October 4, 2017. If implemented, the legislation may prevent the building of pipelines to, and export terminals located on, the portion of the British Columbia coast subject to the moratorium and, as a result, negatively affect the ability of producers to access global markets.

Alberta

The AER is the regulator responsible for all energy resource development in Alberta. It derives its authority from the *Responsible Energy Development Act* (Alberta) and a number of related Acts, including the OGCA, the *Oil Sands Conservation Act* (Alberta), the *Pipeline Act* (Alberta) and the *Environmental Protection and Enhancement Act* (Alberta). The AER is responsible for ensuring the safe, efficient, orderly and environmentally responsible development of hydrocarbon resources, including allocating and conserving water resources, managing public lands and protecting the environment. The AER's responsibilities exclude the functions of the Alberta Utilities Commission and the Surface Rights Board, as well as Alberta Energy's responsibility for mineral tenure.

The Government of Alberta relies on regional planning to accomplish its responsible resource development goals. Its approach to natural resource management provides for engagement and consultation with stakeholders and the public and examines the cumulative impacts of development on the environment and communities by incorporating the management of all resources, including energy, minerals, land, air, water and biodiversity. While the AER is the primary regulator for energy development, several other governmental departments and agencies may be involved in land use issues, including Alberta Environment and Parks, Alberta Energy, the Policy Management Office, the Aboriginal Consultation Office and the Land Use Secretariat.

The Government of Alberta's land-use policy for surface land in Alberta sets out an approach to manage public and private land use and natural resource development in a manner that is consistent with the long-term economic, environmental and social goals of the province. It calls for the development of seven region-specific land-use plans in order to manage the combined impacts of existing and future land use within a specific region and the incorporation of a cumulative effects management approach into such plans. As a result, several regional plans have been implemented and others are in the process of being implemented. These regional plans may affect further development and operations in such regions.

Liability Management Rating Program

In Alberta, the AER administers the licensee Liability Management Rating Program (the "**AB LMR Program**"). The AB LMR Program is a liability management program governing most conventional upstream oil and natural gas wells, facilities and pipelines. It consists of three distinct programs: the Licensee Liability Rating Program (the "**AB LLR Program**"), the Oilfield Waste Liability Program (the "**AB OWL Program**") and the Large Facility Liability Management Program (the "**AB LFP Program**"). At its core, the AER uses the AB LMR Program to aid in determining the ability of licensees to manage the abandonment and reclamation obligations associated with the licensee's assets. If a licensee's deemed liabilities in the AB LLR Program, the AB OWL Program and/or the AB LFP Program exceed its deemed assets in those programs, the AB LMR Program requires the licensee to provide the AER with a security deposit and may restrict the licensee's ability to transfer licences. This ratio of a licensee's assets to liabilities across the three programs is referred to as the licensee's liability management rating ("**LMR**"). The AER assesses the LMR of all licensees on a monthly basis and posts the ratings on the AER's public website. Where the AER determines that a security deposit is required, the failure to post any required amounts may result in the initiation of enforcement action by the AER.

Complementing the AB LMR Program, the OGCA establishes an orphan fund (the "**Orphan Fund**") to help pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline included in the AB LLR Program and the AB OWL Program if a licensee or working interest participant becomes insolvent or is unable to meet its obligations. Licensees in the AB LLR Program and AB OWL Program fund the Orphan Fund through a levy administered by the AER. A separate orphan levy applies to persons holding licences subject to the AB LFP. Collectively, these programs are designed to minimize the risk to the Orphan Fund posed by the unfunded liabilities of licensees and to prevent the taxpayers of Alberta from incurring costs to suspend, abandon, remediate and reclaim wells, facilities or pipelines.

In *Redwater Energy Corporation (Re)* ("**Redwater**"), the Court of Queen's Bench of Alberta found that there was an operational conflict between the abandonment and reclamation provisions of the provincial OGCA, including the AB LLR Program, and the federal BIA. This ruling meant that receivers and trustees of insolvent entities have the right to renounce assets within insolvency proceedings and was affirmed by a majority of the Alberta Court of Appeal. On January 31, 2019, the Supreme Court of Canada overturned the lower courts' decisions, holding that there is no operational conflict between the abandonment and reclamation provisions contained in the provincial OGCA, the liability management regime administered by the AER and the federal bankruptcy and insolvency regime. As a result, receivers and trustees can no longer avoid the AER's legislated authority to impose abandonment orders against licensees or to require a licensee to pay a security deposit before approving a transfer when such a licensee is subject to formal insolvency proceedings. This means that insolvent estates can no longer disclaim assets of a bankrupt licensee that have reached the end of their productive lives and represent a liability while dealing with the company's valuable assets for the benefit of the company's creditors without first satisfying abandonment and reclamation obligations.

In response to the lower courts' decisions in Redwater, the AER issued several bulletins and interim rule changes to govern the AER's administration of its licensing and liability management programs pending a final decision from the Supreme Court of Canada. The AER amended Directive 067, which deals with licence eligibility to operate wells and facilities. The changes to Directive 067 include requiring additional information at the time of application, increased discretion regarding the rejection of applications and requirements for keeping corporate information up to date. Directive 067 also now requires an applicant to provide information regarding the corporate structure of the applicant, whether there are any current regulatory proceedings or outstanding non-compliances, information regarding the applicant's shareholders and whether any directors or officers of the applicant have been directors or officers of an energy company that has been subject to insolvency proceedings in the last five years. All transfers of well, facility and pipeline licences in the province are subject to AER approval. As a condition of transferring existing AER licences, approvals and permits, all transfers are now assessed on a non-routine basis and the AER now requires all transferees to demonstrate that they have an LMR of 2.0 or higher immediately following the transfer, or to otherwise prove to the satisfaction of the AER that it can meet its abandonment and reclamation obligations. The AER may make further rule changes at any time. While the Supreme Court of Canada's Redwater decision alleviates some of the concerns that the AER's rule changes were intended to address, it is unclear how or if the AER will respond.

The AER has also implemented the Inactive Well Compliance Program (the "**IWCP**") to address the growing inventory of inactive wells in Alberta and to increase the AER's surveillance and compliance efforts under Directive 013. The IWCP applies to all inactive wells that are noncompliant with Directive 013 as of April 1, 2015. The objective is to bring all inactive noncompliant wells under the IWCP into compliance with the requirements of Directive 013 within five years. As of April 1, 2015, each licensee is required to bring 20% of its inactive wells into compliance every year, either by reactivating or by suspending the wells in accordance with Directive 013 or by abandoning them in accordance with Directive 020: *Well Abandonment*. The list of current wells subject to the IWCP is available on the AER's Digital Data Submission system.

Climate Change Regulation

Climate change regulation at both the federal and provincial level has the potential to significantly affect the regulation of the oil and natural gas industry in Canada. In general, there is some uncertainty with regard to the impacts of federal or provincial climate change and environmental laws and regulations, as it is currently not possible to predict the extent of future regulatory requirements. Any new laws and regulations, or additional requirements to existing laws and regulations, could have a material impact on the Corporation's operations and cash flow.

Federal

Canada has been a signatory to the United Nations Framework Convention on Climate Change (the "**UNFCCC**") since 1992. Since its inception, the UNFCCC has instigated numerous policy experiments with respect to climate governance. On April 22, 2016, 197 countries signed the Paris Agreement, committing to prevent global temperatures from rising more than 2° Celsius above pre-industrial levels and to pursue efforts to limit this rise to no more than 1.5° Celsius. As of January 1, 2019, 184 of the 197 parties to the convention have ratified the Paris Agreement. Canada ratified the Paris Agreement on October 5, 2016. In December 2018, the United Nations annual Conference of the Parties took place in Katowice, Poland. The Conference concluded with the attendees reiterating their commitment to the targets set out in the Paris Agreement and establishing a transparency framework related to, among other matters, emissions and climate finance reporting.

Following the Paris Agreement and its ratification in Canada, the Government of Canada pledged to cut its emissions by 30% from 2005 levels by 2030. Further, on December 9, 2016, the Government of Canada released the Pan-Canadian Framework on Clean Growth and Climate Change (the "**Pan-Canadian Framework**"). The Pan-Canadian Framework provided for a carbon-pricing strategy, with a carbon tax starting at $10/tonne, increasing annually until it reaches $50/tonne in 2022. A draft legislative proposal for the federal carbon pricing system was released on January 15, 2018. This system would apply in provinces and territories that request it and in those that do not have a carbon pricing system in place that meets the federal standards in 2018. Seven provinces and territories have introduced carbon-pricing systems in place that would meet federal requirements (Alberta, British Columbia, Quebec, Prince Edward Island, Nova Scotia, Newfoundland and Labrador and the Northwest Territories). The federal carbon-pricing regime will take effect in Saskatchewan, Manitoba, Ontario and New Brunswick in April 2019; it will take effect in the Yukon and Nunavut in July 2019. Saskatchewan and Ontario have challenged the constitutionality of the Federal Government's pricing regime; New Brunswick has intervened in Saskatchewan's constitutional challenge. In October 2018, the Federal Government announced an alternative pricing scheme for large electricity generators designed to incentivize a reduction in emissions intensity, rather than encouraging a reduction in generation rates.

On April 26, 2018, the Federal Government passed the *Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector)* (the "**Federal Methane Regulations**"). The Federal Methane Regulations seek to reduce emissions of methane from the oil and natural gas sector, but will not come into force until January 1, 2020. By introducing a number of new control measures, the Federal Methane Regulations aim to reduce unintentional leaks and intentional venting of methane, as well as ensuring that oil and natural gas operations use low-emission equipment and processes. Among other things, the Federal Methane Regulations limit how much methane upstream oil and natural gas facilities are permitted to vent. These facilities would need to capture the gas and either re-use it, re-inject it, send it to a sales pipeline, or route it to a flare. In addition, in provinces other than Alberta and British Columbia (which already regulate such activities), well completions by hydraulic fracturing would be required to conserve or destroy gas instead of venting. The Federal Government anticipates that these actions will reduce annual GHG emissions by about 20 megatonnes by 2030.

Alberta

On November 22, 2015, the Government of Alberta introduced its Climate Leadership Plan (the "**CLP**"). The CLP has four areas of focus: implementing a carbon price on GHG emissions, phasing out coal-generated electricity and developing renewable energy, legislating an oil sands emission limit, and introducing a new methane emissions reduction plan. The Government of Alberta has since introduced new legislation to give effect to these initiatives.

The CLA came into force on January 1, 2017. The CLA and its accompanying regulations impose registration, payment, remittance, reporting and administrative obligations on applicable persons throughout the fuel supply chain. Pursuant to the CLA, an initial economy-wide carbon levy of $20 per tonne of GHG emissions was implemented on January 1, 2017, which increased to $30 per tonne on January 1, 2018. While the levy is anticipated to increase again in 2021 in line with the federal legislation, the Government of Alberta has announced that it will not proceed with the scheduled 2021 increase unless the expansion to the Trans Mountain pipeline proceeds. With certain exemptions, all fuel consumption, including gasoline and natural gas, are subject to the carbon levy. Activities integral to oil and natural gas production processes are exempt until 2023. In addition, facilities subject to CCIR (as described below) are exempt from paying the carbon levy on fuels used in operations.

On December 18, 2017, the Alberta government released the CCIR which came into force January 1, 2018. The CCIR replaces the *Specified Gas Emitters Regulation* ("**SGER**") for compliance years 2018 onwards. The aim is to reduce annual GHG emissions by 20 megatonnes by 2020 and by 50 megatonnes by 2030, and mandates quarterly and final reporting requirements. Similar to SGER, the CCIR applies to any facility that emits 100,000 tonnes of CO_2e per year. Unlike SGER, which set emission reduction requirements, the CCIR imposes an output-based benchmark on competitors in the same emitting industry. The CCIR compliance obligations will be reduced by 50% and 25% for 2018 and 2019, respectively, with no reduction for 2020 onward. In addition to the industry-specific benchmarks, each benchmark will decrease annually at a rate of 1%, beginning in 2020. The Government of Alberta intends for this strategy to align with the Pan-Canadian Framework.

Generally, the CCIR requires each regulated facility to calculate and report its total regulated emissions of specified gases which are compared as against the output-based allocation ("**OBA**") for that facility. Each facility will have an OBA of emissions which is calculated by multiplying the actual quantity of products produced by such facility by such product's benchmark. To the extent a facility's total regulated emissions is less than its OBA, it will earn emission performance credits ("**EPCs**"). To the extent a facility's total regulated emissions exceeds its OBA, the person responsible for such facility will be required to "true-up" by applying EPCs, emission offsets, fund credits or a combination of them, such that its net emissions equal the applicable facility OBA. In January 2019, the Corporation received confirmation of its assigned CCIR benchmark from the Alberta Climate Change Office. The Corporation expects that the Pouce Coupe Gas Plant will generate EPCs in respect of the 2018 financial year.

The Government of Alberta also signaled its intention through the CLP to implement regulations that would lower annual methane emissions by 45% by 2025. Regulations are planned to take effect in 2020 to ensure the 2025 target is met.

Alberta was also the first jurisdiction in North America to direct dedicated funding to implement carbon capture and storage technology across industrial sectors. Alberta has committed $1.24 billion over 15 years to fund two large-scale carbon capture and storage projects that will begin commercializing the technology on the scale needed to be successful. On December 2, 2010, the Government of Alberta passed the *Carbon Capture and Storage Statutes Amendment Act, 2010*. It deemed the pore space underlying all land in Alberta to be, and to have always been, the property of the Crown and provided for the assumption of long-term liability for carbon sequestration projects by the Crown, subject to the satisfaction of certain conditions.

Accountability and Transparency

In 2015, ESTMA came into effect, which imposed mandatory reporting requirements on certain entities engaged in the "commercial development of oil, gas or minerals", including exploration, extraction and holding permits. All companies subject to ESTMA must report payments over CDN$100,000 made to any level of a Canadian or foreign government (including indigenous groups), including royalty payments, taxes (other than consumption taxes and personal income taxes), fees, production entitlements, bonuses, dividends (other than ordinary dividends paid to shareholders), infrastructure improvement payments and other prescribed categories of payments.

RISK FACTORS

Investors should carefully consider the risk factors set out below and consider all other information contained herein and in the Corporation's other public filings before making an investment decision. The risks set out below are not an exhaustive list and should not be taken as a complete summary or description of all the risks associated with the Corporation's business and the oil and natural gas business generally. If any of the risks set out below materialize, the Corporation's business, financial condition, results of operations, prospects, cash flows and reputation may be adversely affected, which may, in turn, reduce or restrict the Corporation's ability to pay dividends and may materially affect the market price of the Corporation's securities.

Financial Risks and Risks Relating to Economic Conditions

Prices, Markets and Marketing

Numerous factors beyond the Corporation's control do, and will continue to, affect the marketability and price of oil and natural gas acquired, produced or discovered by the Corporation. The Corporation's revenues, operating results and financial condition depend substantially on prevailing prices for oil and natural gas and the Corporation's ability to successfully market its oil and natural gas production from its properties.

The Corporation's ability to market its oil and natural gas may depend upon its ability to acquire capacity on pipelines that deliver natural gas, crude oil and NGLs to commercial markets or contract for the delivery of crude oil by rail (see *"Industry Conditions – Transportation Constraints and Market Access", "Risk Factors – Financial Risks and Risks Relating to Economic Conditions – Weakness in the Oil and Gas Industry"* and *"Risk Factors – Business and Operational Risks – Gathering and Processing Facilities, Pipeline Systems and Rail"*). Deliverability uncertainties include the distance the Corporation's reserves are from pipelines, railway lines, processing and storage facilities and operational problems affecting pipelines, railway lines and facilities.

Prices for oil and natural gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors that are beyond the Corporation's control. These factors include, but are not limited to, the following:

- global energy supply and demand;
- the actions taken by OPEC and other oil and gas exporting nations;
- political conditions, instability and hostilities;
- domestic and foreign supplies of crude oil, NGLs and natural gas;
- the level of consumer demand, including demand for different qualities and types of crude oil and NGLs;
- the production and storage levels of North American natural gas and crude oil and the supply and price of imported oil;
- the ability to export oil, LNG and NGLs from North America;
- the availability, proximity and capacity of gathering, transportation, processing and/or refining facilities in regional or localized areas that may affect the realized prices for oil and natural gas;
- weather conditions;
- government regulations, including existing and proposed changes to such regulations;
- the effect of world-wide environmental regulations and energy conservation and GHG reduction measures;

- the price and availability of alternative energy supplies; and
- global and domestic economic conditions, including currency fluctuations.

Oil and natural gas prices are expected to remain volatile for the near future because of market uncertainties over the supply and demand of these commodities due to the current state of the world economy, increased growth of shale oil production in the United States and other concerns of over-supply, OPEC actions, sanctions imposed on certain oil producing nations by other countries, political uncertainties and ongoing credit and liquidity concerns. Volatile oil and natural gas prices make it difficult to estimate the value of producing properties for acquisitions and often cause disruption in the market for oil and natural gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects.

A material decline in oil and natural gas prices could result in a reduction of the Corporation's net production revenue. The economics of producing from some wells may change because of lower prices, which could result in reduced production of oil or natural gas. The Corporation might also elect not to produce from certain wells at lower prices. In addition, any prolonged period of low crude oil or natural gas prices could result in a decision by the Corporation to suspend or slow exploration and development activities or the construction or expansion of new or existing facilities or reduce its production levels. Any substantial and prolonged decline in the price of oil and natural gas would have an adverse effect on the carrying value of the Corporation's assets, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on the Corporation's business, financial condition, results of operations, prospects, its ability to pay dividends and ultimately on the market prices of the Corporation's securities.

Lower commodity prices may also affect the volume and value of the Corporation's reserves, rendering certain reserves uneconomic for development. The Corporation's reserves at December 31, 2018 are estimated using forecast prices and costs. If oil and natural gas prices stay at current levels or decrease, the Corporation's reserves may be substantially reduced as economic limits of developed reserves are reached earlier and undeveloped reserves become uneconomic at such prices. Even if some reserves remain economic at lower price levels, sustained low prices may compel the Corporation to re-evaluate its development plans and reduce or eliminate various projects with marginal economics. Any decrease in the value of the Corporation's reserves may reduce the borrowing base under the Credit Facilities, which, depending on the level of the Corporation's indebtedness, could result in the Corporation having to repay a portion of its indebtedness. See *"Risk Factors – Financial Risks and Risks Relating to Economic Conditions – Credit Facilities".*

In addition, lower commodity prices restrict the Corporation's cash flow resulting in less funds from operations being available to fund the Corporation's capital expenditure programs. The Corporation's capital expenditure plans are impacted by the Corporation's cash flow. Consequently, the Corporation may not be able to replace its production with additional reserves and both the Corporation's production and reserves could be reduced on a year-over-year basis.

In addition to possibly resulting in a decrease in the value of the Corporation's economically recoverable reserves, lower commodity prices may also result in a decrease in the value of the Corporation's infrastructure and facilities, all of which could also have the effect of requiring a write down of the carrying value of its oil and natural gas assets on its balance sheet and the recognition of an impairment charge on its income statement.

Weakness in the Oil and Natural Gas Industry

Recent market events and conditions, including global excess oil and natural gas supply, actions taken by OPEC, slowing growth in China and emerging economies, market volatility and disruptions in Asia, weakening global relationships, isolationist trade policies, increased shale production in the United States, sovereign debt levels and political upheavals in various countries have caused significant weakness and volatility in commodity prices. These events and conditions have caused a significant decrease in the valuation of oil and natural gas companies and a decrease in the confidence in the oil and natural gas industry. These difficulties have been exacerbated in Canada by political and other actions resulting in uncertainty surrounding regulatory, tax, royalty changes and environmental regulation. In addition, the inability to get the necessary approvals to build pipelines, LNG plants and other facilities to provide better access to markets for the oil and natural gas industry in Western Canada has led to additional downward price pressure on oil and natural gas produced in Western Canada and uncertainty and reduced confidence in the oil and natural gas industry in Western Canada. See *"Industry Conditions"*.

Substantial Capital and Additional Funding Requirements

The Corporation anticipates that it will make substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves and resources in the future. As future capital expenditures are expected to be financed out of cash generated from operations, borrowings and possible future equity sales, the Corporation's ability to do so is dependent on, among other factors:

- the overall state of the capital markets;
- the Corporation's credit rating (if applicable);
- commodity prices;
- interest rates;
- royalty rates;
- tax burden due to current and future tax laws; and
- investor appetite for investments in the energy industry and the Corporation's securities in particular.

The Corporation's cash flow from its properties may not be sufficient to fund its ongoing activities at all times and from time to time the Corporation may require additional financing. The inability of the Corporation to access sufficient capital for its operations and activities could have a material adverse effect on the Corporation's financial condition, results of operations and prospects.

Due to the conditions in the oil and natural gas industry and/or global economic and political volatility, the Corporation may from time to time have restricted access to capital and increased borrowing costs. The conditions in or affecting the oil and natural gas industry have negatively impacted the ability of oil and natural gas companies to access additional financing. Failure to obtain financing on a timely basis could cause the Corporation to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations.

There can be no assurance that debt or equity financing or cash generated by operations will be available or sufficient to meet the Corporation's requirements or, if debt or equity financing is available, that it will be on terms acceptable to the Corporation. To the extent that external sources of capital become limited, unavailable or available on onerous terms, the Corporation's ability to make capital investments and maintain existing assets may be impaired, and its assets, liabilities, business, financial condition and results of operations may be affected materially and adversely as a result. In addition, the future development of the Corporation's petroleum properties may require additional financing and there are no assurances that such financing will be available or, if available, will be available upon acceptable terms. The Corporation may be required to seek additional equity financing on terms that are highly dilutive to existing shareholders. Moreover, future activities may require the Corporation to alter its capitalization significantly.

Credit Facilities

The amount authorized under the Credit Facilities is dependent on the borrowing base determined by the Corporation's lenders. The Credit Facilities are subject to a semi-annual review of the borrowing base limit by Birchcliff's syndicate of lenders, which limit is directly impacted by the value of Birchcliff's oil and natural gas reserves. The Corporation's lenders use the Corporation's reserves, commodity prices and other factors to determine the Corporation's borrowing base. Commodity prices continue to be depressed and have fallen dramatically since 2014. Continued depressed commodity prices or further declines in commodity prices could result in a reduction in the Corporation's borrowing base, thereby reducing the funds available to the Corporation under the Credit Facilities. As the borrowing base is determined based on the lender's interpretation of the Corporation's reserves and future commodity prices, there can be no assurance as to the amount of the borrowing base determined at each review. In addition, a majority of lenders have the right once per year to redetermine the borrowing base in between scheduled redeterminations and the borrowing base may also be reduced in connection with asset dispositions. If, at the time of a borrowing base redetermination, the outstanding borrowings under the Credit Facilities were to exceed the borrowing base as a result of any such redetermination, the Corporation would be required to make principal repayments or otherwise eliminate the borrowing base shortfall. If the Corporation is forced to repay a portion of its indebtedness under the Credit Facilities, it may not have sufficient funds to make such repayments. If it does not have sufficient funds and is otherwise unable to negotiate renewals of its borrowings or arrange new financing, it may have to sell significant assets. Any such sale could have a material adverse effect on the Corporation's business and financial results.

The maturity date of the Credit Facilities is currently May 11, 2021. The Corporation may each year, at its option, request an extension to the maturity date of the Syndicated Credit Facility and the Working Capital Facility, or either of them, for an additional period of up to three years from May 11 of the year in which the extension request is made. In the event that either of the Credit Facilities is not extended before the maturity date, all outstanding indebtedness under such Credit Facility will be repayable at the maturity date. There is also a risk that the Credit Facilities will not be renewed for the same principal amount or on the same terms. Any of these events could adversely affect the Corporation's ability to fund its ongoing operations and to pay dividends.

The Corporation is required to comply with covenants under the Credit Facilities. In the event that the Corporation does not comply with these covenants, the Corporation's access to capital could be restricted or repayment could be required. Events beyond the Corporation's control may contribute to the failure of the Corporation to comply with such covenants. A failure to comply with covenants could result in an event of default under the Credit Facilities, which could result in the Corporation being required to repay amounts owing thereunder and may prevent the payment of dividends to shareholders. The acceleration of the Corporation's indebtedness under one agreement may permit acceleration of indebtedness under other agreements that contain cross-default or cross-acceleration provisions. In addition, the Credit Facilities impose certain restrictions on the Corporation, including, but not limited to, restrictions on the payment of dividends, incurring of additional indebtedness, dispositions of properties and the entering into of amalgamations, mergers, plans of arrangements, reorganizations or consolidations with any person. The Credit Facilities do not currently contain any financial maintenance covenants; however, there is no assurance that the Corporation's lenders will not impose any such covenants on the Corporation in the future. Any such covenants may either affect the availability or price of additional funding.

The impact of the Supreme Court of Canada's decision in the Redwater case on lending practices in the oil and natural gas sector and actions taken by secured creditors and receivers/trustees of insolvent borrowers has not yet been determined but could affect lending practices. See *"Industry Conditions – Regulatory Authorities and Environmental Regulation – Alberta – Liability Management Rating Program".*

If the Corporation's lenders require repayment of all or portion of the amounts outstanding under the Credit Facilities for any reason, including for a default of a covenant, there is no certainty that the Corporation would be in a position to make such repayment. Even if the Corporation is able to obtain new financing in order to make any required repayment under the Credit Facilities, it may not be on commercially reasonable terms or terms that are acceptable to the Corporation. If the Corporation is unable to repay amounts owing under the Credit Facilities, the lenders under the Credit Facilities could proceed to foreclose or otherwise realize upon the collateral granted to them to secure the indebtedness.

Dividends

The declaration and payment of dividends (and the amount thereof) is subject to the discretion of the Board and may vary depending on a variety of factors and conditions existing from time to time, including fluctuations in commodity prices, the financial condition of Birchcliff, production levels, results of operations, capital expenditure requirements, working capital requirements, debt service requirements, operating costs, royalty burdens, foreign exchange rates, interest rates, contractual restrictions, Birchcliff's hedging activities or programs, available investment opportunities, Birchcliff's business plan, strategies and objectives, the satisfaction of the solvency and liquidity tests imposed by the ABCA for the declaration and payment of dividends and other factors that the Board may deem relevant. Depending on these and various other factors, many of which are beyond the control of Birchcliff, the dividend policy of the Corporation may vary from time to time and, as a result, future cash dividends could be reduced or suspended entirely.

Pursuant to the ABCA, the Corporation may not declare or pay a dividend if there are reasonable grounds for believing that: (i) the Corporation is, or would after the payment be, unable to pay its liabilities as they become due; or (ii) the realizable value of its assets would thereby be less than the aggregate of its liabilities and stated capital of its outstanding shares. Additionally, pursuant to the agreement governing the Credit Facilities, the Corporation is not permitted to make any distribution (which includes dividends) at any time when an event of default exists or would reasonably be expected to exist upon making such distribution, unless such event of default arose subsequent to the ordinary course declaration of the applicable distribution.

Dividends may be reduced or suspended during periods of lower cash flows from operations. The timing and amount of Birchcliff's capital expenditures, and the ability of the Corporation to repay or refinance existing debt as it becomes due, directly affects the amount of cash dividends that may be declared by the Board. Future acquisitions, expansions of Birchcliff's assets, and other capital expenditures and the repayment or refinancing of existing debt as it becomes due may be financed from sources such as cash flows from operations, the issuance of additional shares or other securities of Birchcliff, and borrowings. Dividends may be reduced, or even eliminated, at times when significant capital or other expenditures are made. There can be no assurance that sufficient capital will be available on terms acceptable to Birchcliff, or at all, to make additional investments, fund future expansions or make other required capital expenditures. To the extent that external sources of capital, including the issuance of additional shares or other securities or the availability of additional credit facilities, become limited or unavailable on favourable terms or at all due to credit market conditions or otherwise, the ability of the Corporation to make the necessary capital investments to maintain or expand its operations, to repay outstanding debt and to invest in assets, as the case may be, may be impaired. To the extent Birchcliff is required to use cash flows from operations to finance capital expenditures or acquisitions or to repay existing debt as it becomes due, the cash available for dividends may be reduced and the level of dividends declared may be reduced.

The market value of the Corporation's securities may deteriorate if dividends are reduced or suspended. Furthermore, the future treatment of dividends for tax purposes will be subject to the nature and composition of dividends paid by Birchcliff and potential legislative and regulatory changes.

Hedging

The Corporation may enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline. Similarly, the Corporation may enter into agreements to fix the differential or discount pricing gap which exists and may fluctuate between different grades of oil, NGLs and natural gas and the various market prices received for such products. However, to the extent that the Corporation engages in price risk management activities to protect itself from commodity price declines, it may also be prevented from realizing the full benefits of price increases above the levels of the derivative instruments used to manage price risk. In addition, if the Corporation enters into hedging arrangements it may be exposed to the risk of financial loss in certain circumstances, including instances in which:

- production falls short of the hedged volumes or prices fall significantly lower than projected;
- there is a widening of price-basis differentials between delivery points for production and the delivery point assumed in the hedge arrangement;
- the counterparties to the hedging arrangements or other price risk management contracts fail to perform under those arrangements; and/or
- a sudden unexpected material event impacts crude oil and natural gas prices.

Similarly, the Corporation may enter into agreements to fix the exchange rate of Canadian dollars to United States dollars or other currencies in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the other currencies. However, if the Canadian dollar declines in value compared to such fixed currencies, the Corporation will not benefit from the fluctuating exchange rate.

Further, the Corporation may enter into hedging arrangements to fix interest rates applicable to the Corporation's debt. However, if interest rates decrease as compared to the interest rate fixed by the Corporation, the Corporation will not benefit from the lower interest rate.

Issuance of Debt

From time to time, the Corporation may finance its activities (including asset acquisitions) in whole or in part with debt, which may increase the Corporation's debt levels above industry standards for peers of similar size. Depending on future exploration and development plans, the Corporation may require additional debt financing that may not be available or, if available, may not be available on favourable terms. Neither the Corporation's articles nor its by-laws limit the amount of indebtedness that the Corporation may incur. The level of the Corporation's indebtedness from time to time could impair the Corporation's ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise.

Credit Risk

The Corporation may be exposed to third-party credit risk through its contractual arrangements with joint venture partners, marketers of its petroleum and natural gas production and other parties. In addition, the Corporation may be exposed to third-party credit risk from operators of properties in which the Corporation has a working or royalty interest. In the event such entities fail to meet their contractual obligations to the Corporation, such failures may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In addition, poor credit conditions in the industry generally and of joint venture partners may affect a joint venture partner's willingness to participate in the Corporation's ongoing capital program, potentially delaying the program and the results of such program until the Corporation finds a suitable alternative partner. To the extent that any of such third parties go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency, it could result in the Corporation being unable to collect all or a portion of any money owing from such parties. Any of these factors could materially adversely affect the Corporation's financial and operational results.

Conversely, the Corporation's counterparties may deem the Corporation to be at risk of defaulting on its contractual obligations. These counterparties may require that the Corporation provide additional credit assurance by prepaying anticipated expenses or posting letters of credit, which would decrease the Corporation's available liquidity.

Variations in Foreign Exchange Rates and Interest Rates

World oil and natural gas prices are quoted in United States dollars. The Canadian/United States dollar exchange rate, which fluctuates over time, consequently affects the price received by Canadian producers of oil and natural gas. Material increases in the value of the Canadian dollar relative to the United States dollar may negatively affect the Corporation's production revenues. Accordingly, Canadian/United States exchange rates could impact the future value of the Corporation's reserves as determined by independent evaluators. Although a low value of the Canadian dollar relative to the United States dollar may positively affect the price the Corporation receives for its oil and natural gas production, it could also result in an increase in the price for certain goods used for the Corporation's operations, which may have a negative impact on the Corporation's financial results.

To the extent that the Corporation engages in risk management activities related to foreign exchange rates, there is credit risk associated with the counterparties with whom the Corporation may contract. See *"Risk Factors – Financial Risks and Risks Relating to Economic Conditions – Hedging"*.

An increase in interest rates could result in a significant increase in the amount the Corporation pays to service debt, resulting in a reduced amount available to fund its exploration and development activities and the cash available for dividends and could negatively impact the market prices of the Corporation's securities.

Business and Operational Risks

Exploration, Development and Production Risks

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of the Corporation depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, any existing reserves the Corporation may have at a particular point in time and the production therefrom, will decline over time as such existing reserves are produced. A future increase in the Corporation's reserves will depend on both the ability of the Corporation to explore and develop its existing properties and its ability to select and acquire suitable producing properties or prospects. There is no assurance that the Corporation will be able to continue to find satisfactory properties to acquire or participate in. Moreover, management of the Corporation may determine that current markets, terms of acquisition, participation or pricing conditions make potential acquisitions or participation uneconomic. There is also no assurance that the Corporation will discover or acquire further commercial quantities of oil and natural gas. The success of the Corporation's business is highly dependent on its ability to acquire or discover new reserves in a cost efficient manner as substantially all of the Corporation's cash flow is derived from the sale of the petroleum and natural gas reserves that it accumulates and develops. In order to remain financially viable, the Corporation must be able to replace reserves over time at a lesser cost on a per unit basis than its cash flow on a per unit basis.

Future oil and natural gas exploration may involve unprofitable efforts from dry wells or wells that are productive but do not produce sufficient petroleum substances to return a profit after drilling, completing (including hydraulic fracturing), operating and other costs. Completion of a well does not ensure a profit on the investment or recovery of drilling, completion and operating costs.

Drilling hazards, environmental damage and various field operating conditions could greatly increase the cost of operations and adversely affect the production from successful wells. Field operating conditions include, but are not limited to, delays in obtaining governmental approvals or consents, the shutting-in of wells resulting from extreme weather conditions, insufficient storage or transportation capacity or geological and mechanical conditions. While diligent well supervision, effective maintenance operations and the development and utilization of enhanced recovery technologies can contribute to maximizing production rates over time, it is not possible to eliminate production delays and declines from normal field operating conditions, which can negatively affect revenue and cash flow levels to varying degrees.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including, but not limited to, fire, explosion, blowouts, cratering, sour gas releases, spills and other environmental hazards. These typical risks and hazards could result in substantial damage to oil and natural gas wells, production facilities, other property or the environment and cause personal injury or threaten wildlife. Particularly, the Corporation may explore for and produce sour natural gas in certain areas. An unintentional leak of sour natural gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability to the Corporation.

Oil and natural gas production operations are also subject to geologic and seismic risks, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

As is standard industry practice, the Corporation is not fully insured against all risks, nor are all risks insurable. Although the Corporation maintains liability and business interruption insurance in amounts that it considers consistent with industry practice, liabilities associated with certain risks could exceed policy limits or not be covered. In either event, the Corporation could incur significant costs. See *"Risk Factors – Other Risks – Insurance"*.

Gathering and Processing Facilities, Pipeline Systems and Rail

The Corporation delivers its products through gathering and processing facilities, pipeline systems and, in certain circumstances, by rail. The amount of oil and natural gas that the Corporation can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering and processing facilities, pipeline systems and railway lines. Notwithstanding recent actions taken by the Government of Alberta (see *"Industry Conditions"*), the ongoing lack of availability of capacity in any of the gathering and processing facilities, pipeline systems and railway lines could result in the Corporation's inability to realize the full economic potential of its production or in a reduction of the price offered for the Corporation's production. The lack of firm pipeline capacity continues to affect the oil and natural gas industry and limits the ability to transport produced oil and natural gas to market. In addition, the pro-rationing of capacity on inter-provincial pipeline systems continues to affect the ability to export oil and natural gas. Unexpected shut-downs or curtailment of capacity of pipelines for maintenance or integrity work or because of actions taken by regulators could also affect the Corporation's production, operations and financial results. As a result, producers are increasingly turning to rail as an alternative means of transportation. In recent years, the volume of crude oil shipped by rail in North America has increased dramatically. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays or uncertainties in constructing new infrastructure systems and facilities, could harm the Corporation's business and, in turn, the Corporation's financial condition, results of operations and cash flows. Announcements and actions taken by the Federal Government and the provincial governments of British Columbia, Alberta and Quebec relating to the approval of infrastructure projects may continue to intensify, leading to increased challenges to interprovincial and international infrastructure projects moving forward. In addition, while the Federal Government has introduced Bill C-69 to overhaul the existing environmental assessment process and replace the NEB with a new regulatory agency, the impact of the new proposed regulatory scheme on proponents and the timing of receipt of approvals of major projects remains unclear. See *"Industry Conditions – Regulatory Authorities and Environmental Regulation".*

Following major accidents in Lac-Megantic, Quebec and North Dakota, the Transportation Safety Board of Canada and the U.S. National Transportation Board recommended additional regulations for railway tank cars carrying crude oil. In June 2015, as a result of these recommendations, the Government of Canada passed the *Safe and Accountable Rail Act* which increased insurance obligations on the shipment of crude oil by rail and imposed a per tonne levy of $1.65 on crude oil shipped by rail to compensate victims and for environmental cleanup in the event of a railway accident. In addition to this legislation, new regulations have implemented the TC-117 standard for all rail tank cars carrying flammable liquids which formalized the commitment to retrofit, and phase out DOT-111 tank cars carrying crude oil. The increased regulation of rail transportation may reduce the ability of railway transportation to alleviate pipeline constraints and adds additional costs to the transportation of crude oil by rail. On July 13, 2016, the Minister of Transport (Canada) issued Protective Direction No. 38, which directed that the shipping of crude oil on DOT-111 tank cars end by November 1, 2016. Tank cars entering Canada from the United States will be monitored to ensure they are compliant with Protective Direction No. 38.

The Corporation's production passes through Birchcliff owned or third-party infrastructure prior to it being ready for sale. There is a risk that should this infrastructure fail and cause a significant portion of the Corporation's production to be shut-in and unable to be sold, this could have a material adverse effect on the Corporation's available cash flow. With respect to facilities owned by third parties and over which the Corporation has no control, these facilities may discontinue or decrease operations either as a result of normal servicing requirements or as a result of unexpected events. A discontinuation or decrease of operations could have a material adverse effect on the Corporation's ability to process its production and deliver the same to market. Midstream and pipeline companies may take actions to maximize their return on investment which may in turn adversely affect producers and shippers, especially when combined with a regulatory framework that may not always align with the interests of particular shippers.

Further, the Corporation has certain long-term take-or-pay commitments to deliver products through third-party owned infrastructure which creates a financial liability and there can be no assurance that future volume commitments will be met which may adversely affect the Corporation's financial condition and cash flows from operations.

Project Risks

The Corporation manages a variety of small and large projects in the conduct of its business. Project delays and interruptions may delay expected revenues from operations. Significant project cost overruns could make a project uneconomic. The Corporation's ability to execute projects and successfully market its oil and natural gas depends upon numerous factors beyond the Corporation's control, including:

- the availability and proximity of processing and pipeline capacity;
- the availability of storage capacity;
- the availability of, and the ability to acquire, water supplies needed for drilling and hydraulic fracturing and the Corporation's ability to dispose of water used or removed from strata at a reasonable cost and in accordance with applicable environmental regulations;
- the effects of inclement weather;
- the availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- regulatory changes;
- the availability and productivity of skilled labour; and
- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

Because of these factors, the Corporation could be unable to execute projects on time, on budget, or at all, and may be unable to effectively market the oil and natural gas that it produces.

Uncertainty of Reserves and Resource Estimates

There are numerous uncertainties inherent in estimating oil, natural gas and NGLs reserves and the future net revenue attributed to such reserves. The reserves and associated future net revenue information set forth in this Annual Information Form are estimates only. In general, estimates of economically recoverable oil, natural gas and NGLs reserves and the future net revenue therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserves recovery, the timing and amount of capital expenditures, marketability of oil, natural gas and NGLs, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially from actual results. For these reasons, estimates of the economically recoverable oil, natural gas and NGLs reserves attributable to any particular group of properties, the classification of such reserves based on risk of recovery and estimates of future net revenue associated with reserves prepared by different engineers, or by the same engineer at different times, may vary. The Corporation's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material.

The estimation of proved reserves that may be developed and produced in the future is often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Recovery factors and drainage areas are often estimated by experience and analogy to similar producing pools. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history and production practices will result in variations in the estimated reserves and such variations could be material.

In accordance with applicable securities laws in Canada, the Corporation's independent qualified reserves evaluators have used forecast prices and costs in estimating the reserves and future net revenue as summarized herein. Actual future net revenue will be affected by other factors such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulations or taxation and the impact of inflation on costs.

Actual production and cash flows derived from the Corporation's reserves will vary from the estimates contained in the Corporation's independent reserves evaluations and such variations could be material. The independent reserves evaluations are based in part on the assumed success of activities the Corporation intends to take in future years. The reserves and estimated future net revenue to be derived therefrom and contained in the Corporation's independent reserves evaluations will be reduced to the extent that such activities do not achieve the level of success assumed in the evaluations.

This Annual Information Form also contains estimates of the volumes of the Corporation's contingent resources and prospective resources, as well as the net present value of the future net revenue associated with the best estimate of development pending contingent resources. The same uncertainties inherent in estimating quantities of reserves apply to estimating quantities of contingent resources. The uncertainty in estimating prospective resources is even greater. Actual results may vary significantly from these estimates and such variances could be material. In addition, there are contingencies that prevent contingent resources from being classified as reserves. With respect to the Corporation's contingent resources, there is uncertainty that it will be commercially viable to produce any portion of the resources. With respect to the Corporation's prospective resources, there is no certainty that any portion of the resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources.

The Consolidated Reserves Report, the Deloitte Reserves Report, the McDaniel Reserves Report and the 2018 Resource Assessment are effective as of December 31, 2018 and, except as may be specifically stated or required by applicable securities laws, have not been updated since that date and therefore do not reflect changes since that date.

Availability and Cost of Equipment and Services

Oil and natural gas exploration, development and operating activities are dependent on the availability and cost of specialized equipment and other materials (typically leased from third parties) and skilled personnel trained to use such equipment in the areas where such activities will be conducted. The availability of such equipment, materials and personnel is limited. An increase in demand or cost, or a decrease in the availability of, such equipment, materials or personnel may impede the Corporation's exploration, development and operating activities, which, in turn, could materially adversely affect the Corporation's business and financial condition.

Potential Future Drilling Locations

The Corporation's identified potential future drilling locations represent a significant part of the Corporation's future growth. The Corporation's ability to drill and develop these locations and the drilling locations on which it actually drills wells depends on a number of uncertainties and factors, including, but not limited to, the availability of capital, equipment and personnel, oil and natural gas prices, costs, inclement weather, seasonal restrictions, drilling results, additional geological, geophysical and reservoir information that is obtained, production rate recovery, gathering system and transportation constraints, the net price received for commodities produced, regulatory approvals and regulatory changes. As a result of these uncertainties, there can be no assurance that the potential future drilling locations that Birchcliff has identified will ever be drilled and, if drilled, that such locations will result in additional oil, NGLs or natural gas production and, in the case of unbooked locations, additional reserves. As such, the Corporation's actual drilling activities may differ materially from those presently identified, which could adversely affect the Corporation's business.

Seasonality and Extreme Weather Conditions

The level of activity in the Canadian oil and natural gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments may enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Road bans and other restrictions generally result in a reduction of drilling and exploratory activities and may also result in the shut-in of some of the Corporation's production if not otherwise tied-in. In addition, certain oil and natural gas producing properties are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. Further, extreme cold weather, heavy snowfall and heavy rainfall may restrict the Corporation's ability to access its properties and cause operational difficulties including damage to machinery or contribute to personnel injury because of dangerous working conditions. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and also to volatility in commodity prices as the demand for natural gas typically fluctuates during cold winter months and hot summer months.

Competition

The oil and natural gas industry is highly competitive in all of its phases. The Corporation competes with numerous other entities in the exploration, development, production and marketing of oil and natural gas, including land, acquisitions of reserves, access to drilling and service rigs and other equipment, access to transportation and skilled technical and operating personnel. The Corporation's competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than those of the Corporation. Some of these companies not only explore for, develop and produce oil and natural gas, but also carry on refining operations and market oil and natural gas on an international basis. As a result of these complementary activities, some of these competitors may have greater and more diverse competitive resources to draw on than the Corporation. The Corporation'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.

Hydraulic Fracturing

Hydraulic fracturing involves the injection of water, sand and small amounts of additives under pressure into rock formations to stimulate the production of oil and natural gas. Specifically, hydraulic fracturing enables the production of commercial quantities of oil and natural gas from reservoirs that were previously unproductive. While hydraulic fracturing has been in use for many years, there has been increased focus on the environmental aspects of hydraulic fracturing practices in recent years. Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition (including litigation) to oil and natural gas production activities using hydraulic fracturing techniques. Any new laws, regulations or permitting requirements regarding hydraulic fracturing could lead to operational delays, increased operating costs, third-party or governmental claims and could increase the Corporation's costs of compliance and doing business, as well as delay the development of oil and natural gas resources from certain formations which are not commercial without the use of hydraulic fracturing. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that the Corporation is ultimately able to produce from its reserves and, therefore, could adversely affect the Corporation's business, financial condition, results of operations and prospects.

All Assets in One Area

All of the Corporation's producing properties are geographically concentrated in the Peace River Arch area of Alberta. As a result of this concentration, the Corporation may be disproportionately exposed to the impact of delays or interruptions of production from that area caused by transportation capacity constraints, curtailment of production, natural disasters, availability of equipment, facilities or services, adverse weather conditions or other events which impact that area. Due to the concentrated nature of the Corporation's portfolio of properties, a number of the Corporation's properties could experience any of the same conditions at the same time, resulting in a relatively greater impact on the Corporation's results of operations than they might have on other companies that have a more diversified portfolio of properties. Such delays or interruptions could have a material adverse effect on the Corporation's financial condition and results of operations.

Operational Dependence

Other companies operate some of the assets in which the Corporation has an interest. The Corporation has limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect the Corporation's business, financial condition, results of operations and prospects. The Corporation's return on assets operated by others depends upon a number of factors that may be outside of the Corporation's control, including, but not limited to, the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

In addition, due to the current low and volatile commodity price environment, many companies, including companies that may operate some of the assets in which the Corporation has an interest, may be in financial difficulty, which could impact their ability to fund and pursue capital expenditures, carry out their operations in a safe and effective manner and satisfy regulatory requirements with respect to abandonment and reclamation obligations. If companies that operate some of the assets in which the Corporation has an interest fail to satisfy regulatory requirements with respect to abandonment and reclamation obligations, the Corporation may be required to satisfy such obligations and to seek recourse from such companies. To the extent that any of such companies go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency, it could result in such assets being shut-in, the Corporation potentially becoming subject to additional liabilities relating to such assets and the Corporation having difficulty collecting revenue due to it from such operators or recovering amounts owing to the Corporation from such operators for their share of abandonment and reclamation obligations. Any of these factors could have a material adverse effect on the Corporation's financial and operational results.

Expiration of Licences and Leases

The Corporation's properties are held in the form of licences and leases and working interests in licences and leases held by others. If the Corporation or the holder of the licence or lease fails to meet the specific requirements of a licence or lease, the licence or lease may terminate or expire. There can be no assurance that any of the obligations required to maintain each licence or lease will be met. The termination or expiration of the Corporation's licences or leases or the working interests relating to a licence or lease may have a material adverse effect on the business, financial condition, results of operations and prospects of the Corporation.

Cost of New Technologies

The oil and natural gas industry is characterized by rapid and significant technological advancements and introductions of new products and services utilizing new technologies. Other oil and natural gas companies may have greater financial, technical and personnel resources that allow them to implement and benefit from new technologies before the Corporation. There can be no assurance that the Corporation will be able to respond to such competitive pressures and implement such technologies on a timely basis or at an acceptable cost. If the Corporation implements such technologies, there is no assurance that the Corporation will do so successfully. One or more of the technologies currently utilized by the Corporation or implemented in the future may become obsolete. In such case, the Corporation's business, financial condition, results of operations and prospects could be affected adversely and materially. If the Corporation is unable to utilize the most advanced commercially available technology or is unsuccessful in implementing certain technologies, its business, financial condition, results of operations and prospects could also be adversely affected in a material way.

Alternatives to and Changing Demand for Petroleum Products

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas and technological advances in fuel economy and renewable energy generation devices could reduce the demand for oil, natural gas and liquid hydrocarbons. Recently, certain jurisdictions have implemented policies or incentives to decrease the use of fossil fuels and encourage the use of renewable fuel alternatives, which may lessen the demand for petroleum products and put downward pressure on commodity prices. In addition, advancements in energy efficient products have a similar effect on the demand for oil and natural gas products. The Corporation cannot predict the impact of the changing demand for oil and natural gas products and any major changes may have a material adverse effect on the Corporation's business, financial condition, results of operations and cash flows by decreasing the Corporation's profitability, increasing its costs, limiting its access to capital or decreasing the value of its assets.

Expansion into New Activities

The operations and expertise of the Corporation's management are currently focused primarily on oil and natural gas production, exploration and development in the Peace River Arch area of Alberta. In the future, the Corporation may acquire or move into new industry-related activities or new geographical areas or may acquire different energy-related assets, and as a result, the Corporation may face unexpected risks or alternatively, the Corporation's exposure to one or more existing risk factors may be significantly increased, which may in turn result in the Corporation's future operational and financial condition being adversely affected.

Regulatory, Political and Environmental Risks

Regulatory

Various levels of governments impose extensive controls and regulations on oil and natural gas operations (including exploration, development, production, pricing, marketing, transportation and infrastructure). Governments may regulate or intervene with respect to exploration and production activities, prices, taxes, royalties, the exportation of oil and natural gas and infrastructure projects. Amendments to these controls and regulations may occur from time to time in response to economic or political conditions. The implementation of new regulations or the modification to existing regulations affecting the oil and natural gas industry could reduce the demand for crude oil and natural gas and increase the Corporation's costs or make certain projects uneconomic, which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Although the current Federal Government has introduced Bill C-69 to overhaul the existing environmental assessment process and replace the NEB with a new regulatory agency, the impact of the new proposed regulatory scheme on proponents and the timing of receipt of approvals of major projects remains unclear. See *"Industry Conditions – Transportation Constraints and Market Access"* and *"Industry Conditions – Regulatory Authorities and Environmental Regulation".*

Even when projects are approved at 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. 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. The ongoing third-party challenges to regulatory decisions or orders has reduced the efficiency of the regulatory regime, as the implementation of the decisions and orders has been delayed resulting in uncertainty and interruption to business of the oil and natural gas industry. See *"Industry Conditions – Transportation Constraints and Market Access"* and *"Industry Conditions – Regulatory Authorities and Environmental Regulation".*

Recently, the Federal Government and certain provincial governments have taken steps to initiate protocols and regulations to limit the release of methane from oil and natural gas operations. Such draft regulations and protocols may require additional expenditures or otherwise negatively impact the Corporation's operations and may affect the Corporation's revenues and financial condition. See *"Industry Conditions – Climate Change Regulation".*

Further, in response to widening pricing differentials, the Government of Alberta implemented production curtailment. See *"Industry Conditions – Curtailment".* The Corporation is not currently subject to a curtailment order; however, no assurance can be given that the Government of Alberta will not in the future enact rules which would require the Corporation to curtail its production.

In order to conduct oil and natural gas operations, the Corporation requires regulatory permits, licences, registrations, approvals and authorizations from various governmental authorities. There can be no assurance that the Corporation will be able to obtain all of the permits, licences, registrations, approvals and authorizations that may be required to conduct operations that it may wish to undertake. In addition, the Corporation may have to comply with the requirements of certain federal legislation such as the *Competition Act* (Canada) and the *Investment Canada Act* (Canada), which may adversely affect its business and financial condition and the market value of its securities or assets, particularly when undertaking, or attempting to undertake, an acquisition or disposition.

Political Uncertainty

In the last several years, the United States and certain European countries have experienced significant political events that have cast uncertainty on global financial and economic markets.

Since the 2016 U.S. presidential election, the current United States administration has begun taking steps to implement certain of its promises made during the campaign. The administration has withdrawn the United States from the Trans-Pacific Partnership and Congress has passed sweeping tax reform, which, among other things, significantly reduces U.S. corporate tax rates. This may affect competitiveness of other jurisdictions, including Canada. In addition, NAFTA was renegotiated and on November 30, 2018, Canada, the U.S. and Mexico signed USMCA which will replace NAFTA once ratified by the three signatory countries (see *"Industry Conditions – NAFTA and Other Trade Agreements"*). The administration has also taken action with respect to reducing regulation which may also affect the relative competitiveness of other jurisdictions. It is unclear exactly what other actions the United States administration will implement, and if implemented, how these actions may impact Canada and in particular the oil and natural gas industry. Any actions taken by the current United States administration may have a negative impact on the Canadian economy and on the businesses, financial condition, results of operations, prospects and the valuation of Canadian oil and natural gas companies, including the Corporation.

In addition to the political disruption in the United States, the citizens of the United Kingdom voted to withdraw from the European Union and the Government of the United Kingdom has taken steps to implement such withdrawal. The terms of the United Kingdom's exit from the European Union and whether it will occur at all remain to be determined. Some European countries have also experienced the rise of anti-establishment political parties and public protests held against open-door immigration policies, trade and globalization. To the extent that certain political actions taken in North America, Europe and elsewhere in the world result in a marked decrease in free trade, access to personnel and freedom of movement, it could have an adverse effect on the Corporation's ability to market its products internationally, increase costs for goods and services required for the Corporation's operations, reduce access to skilled labour and negatively impact the Corporation's business, operations, financial condition and the market value of its securities.

A change in federal, provincial or municipal governments in Canada may have an impact on the directions taken by such governments on matters that may impact the oil and natural gas industry, including the balance between economic development and environmental policy such as the potential impact of the recent change of government in British Columbia and announcements and actions by the Government of British Columbia that may impact the completion of the Trans-Mountain Pipeline project, LNG facilities and other infrastructure projects.

Geopolitical Risks

Political changes in North America and political instability in the Middle East and elsewhere may cause disruptions in the supply of oil that affects the marketability and price of crude oil and natural gas. Conflicts, or conversely peaceful developments, arising outside of Canada, including changes in political regimes or parties in power, may have a significant impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and result in a reduction of the Corporation's revenue.

Environmental

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with oil and natural gas industry operations. In addition, such legislation sets out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites.

Compliance with environmental legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Corporation to incur costs to remedy such discharge. Although the Corporation believes that it is in material compliance with current applicable environmental legislation, no assurance can be given that environmental compliance requirements will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

In addition, political and economic events may significantly affect the scope and timing of climate change measures that are put in place. The implementation of new environmental regulations or the modification of existing environmental regulations affecting the oil and natural gas industry generally could reduce demand for oil and natural gas and increase costs. See *"Risk Factors – Regulatory, Political and Environmental Risks – Climate Change"*.

Climate Change

The Corporation's exploration and production facilities and other operations and activities emit GHGs which requires the Corporation to comply with applicable GHG emissions legislation. Climate change policy is evolving at regional, national and international levels and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place. As a signatory to the UNFCCC and the Paris Agreement, the Government of Canada pledged to cut its GHG emissions by 30% from 2005 levels by 2030. One of the pertinent policies announced to date by the Government of Canada to reduce GHG emissions is the planned implementation of a nation-wide price on carbon emissions. The federal carbon levy goes into effect April 1, 2019 and will affect those provinces that have not implemented their own carbon taxes, cap-and-trade systems or other plans for carbon pricing, namely Ontario, Manitoba, Saskatchewan and New Brunswick. The federal carbon levy will be at an initial rate of $20 per tonne. Provincially, the Government of Alberta has already implemented a carbon levy on almost all sources of GHG emissions, now at a rate of $30 per tonne. The implementation of the federal carbon levy is currently subject to constitutional challenges by the Provinces of Saskatchewan and Ontario, which are supported by the Province of New Brunswick.

Concerns about climate change have resulted in a number of environmental activists and members of the public opposing the continued exploitation and development of fossil fuels. Historically, political and legal opposition to the fossil fuel industry focused on public opinion and the regulatory process. More recently, however, there has been a movement to more directly hold governments and oil and natural gas companies responsible for climate change through climate litigation. In November 2018, ENvironment JEUnesse, a Quebec advocacy group, applied to the Quebec Superior Court to certify a class action against the Government of Canada for climate related matters. In January 2019, the City of Victoria became the first municipality in Canada to endorse exploring the initiation of a class action lawsuit against oil and natural gas producers for climate-related harms. See *"Risk Factors – Non-Governmental Organizations and Eco-Terrorism Risks"* and *"Risk Factors – Public Opinion and Reputational Risk ".*

In addition, there has been public discussion that climate change may be associated with extreme weather conditions and increased volatility in seasonal temperatures. Extreme weather could interfere with the Corporation's production and increase the Corporation's costs. At this time, the Corporation is unable to determine the extent to which climate change may lead to increased storm or weather hazards affecting its operations.

The direct or indirect costs of compliance with GHG-related legislation may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. Adverse impacts to the Corporation's business as a result of GHG legislation may include, but are not limited to, increased compliance costs, permitting delays, increased operating costs and capital expenditures and reduced demand for the oil, natural gas and NGLs that the Corporation produces. In addition, the Pouce Coupe Gas Plant is subject to the CCIR and some of the Corporation's other significant facilities may ultimately become subject to future regional, provincial and/or federal climate change regulations to manage GHG emissions. Given the evolving nature of the debate related to climate change and the control of GHG and resulting requirements, it is expected that current and future climate change regulations will have the effect of increasing the Corporation's operating expenses and in the long-term reducing the demand for oil and natural gas production resulting in a decrease in the Corporation's profitability and a reduction in the value of its assets or asset write-offs. See *"Description of the Business – Environmental Protection – Environmental Costs and Decommissioning Obligations"* and *"Industry Conditions – Climate Change Regulation".*

Carbon Pricing Risk

The majority of countries across the globe have agreed to reduce their carbon emissions in accordance with the Paris Agreement. In Canada, the Federal Government and certain provincial governments have implemented legislation aimed at incentivizing the use of alternative fuels and in turn reducing carbon emissions. See *"Industry Conditions – Climate Change Regulation"* and *"Risk Factors – Regulatory, Political and Environmental Risks – Climate Change"*.

The taxes placed on carbon emissions may have the effect of decreasing the demand for oil and natural gas products and at the same time, increasing the Corporation's operating expenses, each of which may have a material adverse effect on the Corporation's profitability and financial condition. Further, the imposition of carbon taxes puts the Corporation at a disadvantage with its counterparts who operate in jurisdictions where there are less costly carbon regulations.

Liability Management Programs

Alberta has developed the AB LMR Program which is designed to prevent taxpayers from incurring costs associated with the suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licensee or permit holder is unable to satisfy its regulatory obligations. This program involves an assessment of the ratio of a licensee's deemed assets to deemed liabilities. If a licensee's deemed liabilities exceed its deemed assets, a security deposit is generally required. Changes to the required ratio of the Corporation's deemed assets to deemed liabilities or other changes to the requirements of the AB LMR Program may result in the requirement for security to be posted in the future and may result in significant increases to the Corporation's compliance obligations. In addition, the AB LMR Program may prevent or interfere with the Corporation's ability to acquire or dispose of assets as both the vendor and the purchaser of oil and natural gas assets must be in compliance with the AB LMR Program (both before and after the transfer of the assets) for the applicable regulatory agency to allow for the transfer of such assets.

The impact and consequences of the Supreme Court of Canada's decision in the Redwater case on the AER's rules and policies, lending practices in the crude oil and natural gas sector and on the nature and determination of secured lenders to take enforcement proceedings will no doubt evolve as the consequences of the decision are evaluated and considered by regulators, lenders and receivers/trustees. See *"Industry Conditions – Regulatory Authorities and Environmental Regulation – Alberta – Liability Management Rating Program"*.

Royalty Regimes

There can be no assurance that the Government of Alberta will not adopt a new royalty regime or modify the existing royalty regime, which may have an impact on the economics of the Corporation's projects. An increase in royalties would reduce the Corporation's earnings and could make future capital investments, or the Corporation's operations, less economic or uneconomic. On January 29, 2016, the Government of Alberta adopted a new royalty regime which took effect on January 1, 2017. See *"Industry Conditions – Royalties and Incentives".*

Disposal of Fluids Used in Operations

The safe disposal of the hydraulic fracturing fluids (including the additives) and water recovered from oil and natural gas wells is subject to ongoing regulatory review by the federal and provincial governments, including its effect on fresh water supplies and the ability of such water to be recycled, amongst other things. While it is difficult to predict the impact of any regulations that may be enacted in response to such review, the implementation of stricter regulations may increase the Corporation's costs of compliance which may impact the economics of certain projects and, in turn, impact activity levels and new capital spending on the Corporation's oil and natural gas properties.

Other Risks

Market Prices of the Corporation's Securities

The market price of the Corporation's securities may be volatile, which may affect the ability of holders to sell such securities at an advantageous price. The trading price of securities of oil and natural gas issuers is subject to substantial volatility often based on factors related and unrelated to the financial performance or prospects of the issuers involved. Factors unrelated to the Corporation's performance could include macroeconomic developments nationally, within North America or globally, domestic and global commodity prices or current perceptions of the oil and natural gas market. In recent years, the volatility of commodities has increased due to, in part, the implementation of computerized trading and the decrease of discretionary commodity trading. In addition, in certain jurisdictions, institutions, including government-sponsored entities, have determined to decrease their ownership in oil and natural gas entities which may impact the liquidity of certain securities and may put downward pressure on the trading price of those securities. Similarly, the market prices of the Corporation's securities could be subject to significant fluctuations in response to variations in the Corporation's operating results, financial condition, liquidity and other internal factors. In addition, market price fluctuations in the Corporation's securities may also be due to the Corporation's results failing to meet the expectations of securities analysts or investors in any quarter, downward revision in securities analysts' estimates and material public announcements by the Corporation, along with a variety of additional factors, including, without limitation, those set forth under "*Special Notes to Reader – Forward-Looking Statements"*. Accordingly, the prices at which the Corporation's securities will trade cannot be accurately predicted.

Reliance on Key Personnel

The Corporation's success depends, in large measure, on certain key personnel. The loss of the services of such key personnel could have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. The Corporation does not have any key personnel insurance in effect. The contributions of the existing management team to the immediate and near-term operations of the Corporation are likely to be of central importance. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that the Corporation will be able to continue to attract and retain all of the personnel necessary for the development and operation of its business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of the Corporation's management.

Skilled Workforce

An inability to recruit and retain a skilled workforce may negatively impact the Corporation. The operations and management of the Corporation require the recruitment and retention of a skilled workforce, including engineers, technical personnel and other professionals. The loss of key members of such workforce, or a substantial portion of the workforce as a whole, could result in the failure to implement the Corporation's business plans. The Corporation competes with other companies in the oil and natural gas industry as well as other industries for this skilled workforce. A decline in market conditions has led to increasing numbers of skilled personnel to seek employment in other industries. In addition, certain of the Corporation's current employees are senior and have significant institutional knowledge that must be transferred to other employees prior to their departure from the workforce. If the Corporation is unable to retain current employees, successfully complete effective knowledge transfers and/or recruit new employees with comparable knowledge and experience, the Corporation could be negatively impacted. In addition, the Corporation could experience increased costs to retain and recruit these professionals.

Public Opinion and Reputational Risk

The Corporation's business, financial condition, operations or prospects may be negatively impacted as a result of any negative public opinion towards the Corporation or as a result of any negative sentiment towards, or in respect of, the Corporation's reputation with stakeholders, special interest groups, political leadership, the media or other entities. Public opinion may be influenced by certain media and special interest groups' negative portrayal of the industry in which the Corporation operates, as well as their opposition to certain oil and natural gas projects. Potential impacts of negative public opinion or reputational issues may include delays or interruptions in operations, legal or regulatory actions or challenges, blockades, increased regulatory oversight, reduced support for, delays in, challenges to, or the revocation of regulatory approvals, permits and/or licences and increased costs and/or cost overruns.

Any environmental damage, loss of life, injury or damage to property caused by the Corporation's operations could damage its reputation. Negative sentiment towards the Corporation could result in a lack of willingness of municipal authorities to grant the necessary licenses or permits for the Corporation to operate its business. In addition, negative sentiment towards the Corporation could result in the residents of the areas where the Corporation is doing business opposing further operations in the area by the Corporation. If the Corporation develops a reputation of having an unsafe work site, this may impact its ability to attract and retain the necessary skilled employees and consultants to operate its business. Further, the Corporation's reputation could be affected by actions and activities of other corporations operating in the oil and natural gas industry, particularly other producers, over which the Corporation has no control. Further, opposition from special interest groups opposed to oil and natural gas development and the possibility of climate related litigation against governments and fossil fuel companies may impact the Corporation's reputation. See *"Risk Factors – Regulatory, Political and Environmental Risks – Climate Change".*

Reputational risk cannot be managed in isolation from other forms of risk. Credit, market, operational, insurance, regulatory and legal risks, among others, must all be managed effectively to safeguard the Corporation's reputation. Damage to the Corporation's reputation could result in in negative investor sentiment towards the Corporation, which may result in limiting the Corporation's access to capital, increasing the cost of capital and decreasing the price and liquidity of the Corporation's securities.

Changing Investor Sentiment

A number of factors, including the concerns of the effects of the use of fossil fuels on climate change, concerns of the impact of oil and natural gas operations on the environment, concerns of environmental damage relating to spills of petroleum products during transportation and concerns of indigenous rights, have affected certain investors' sentiments towards investing in the oil and natural gas industry. As a result of these concerns, some institutional, retail and public investors have announced that they no longer are willing to fund or invest in oil and natural gas properties or companies or are reducing the amount thereof over time. In addition, certain institutional investors are requesting that issuers develop and implement more robust social, environmental and governance policies and practices. Developing and implementing such policies and practices can involve significant costs and require a significant time commitment from the Corporation's Board, management and employees. Failing to implement the policies and practices as requested by institutional investors may result in such investors reducing their investment in the Corporation or not investing in the Corporation at all. Any reduction in the investor base interested or willing to invest in the oil and natural gas industry and more specifically, in the Corporation, may result in limiting Birchcliff's access to capital, increasing the cost of capital and decreasing the price and liquidity of the Corporation's securities, even if the Corporation's operating results, underlying asset value or prospects have not changed. Additionally, these factors, as well as other related factors, may cause a decrease in the value of the Corporation's assets which may result in an impairment charge.

Non-Governmental Organizations and Eco-Terrorism Risks

The crude oil and natural gas industry may, at times, be subject to public opposition. Such public opposition could expose the Corporation to the risk of higher costs, delays or even project cancellations due to increased pressure on governments and regulators by special interest groups including Aboriginal groups, landowners, environmental interest groups (including those opposed to oil and gas production operations) and other non-governmental organizations. Potential impacts of such pressure and opposition include blockades, legal or regulatory actions or challenges, increased regulatory oversight, reduced support of the federal, provincial or municipal governments, and delays in, challenges to, or the revocation of regulatory approvals, permits and/or licences. There is no guarantee that the Corporation will be able to satisfy the concerns of the special interest groups and non-governmental organizations and attempting to address such concerns may require significant and unanticipated capital and operating expenditures which may negatively impact the Corporation's business, financial condition, results of operations and prospects.

In addition, the Corporation's oil and natural gas properties, wells and facilities or the third-party facilities and pipelines utilized by the Corporation could be the subject of a terrorist attack. If any of such properties, wells or facilities are the subject of terrorist attack, it may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Management of Growth and Integration

The Corporation may be subject to both integration and growth-related risks, including capacity constraints and pressure on its internal systems and controls. The ability of the Corporation to effectively manage growth and the integration of additional assets will require it to continue to implement and improve its operational and financial systems and to expand, train and manage its employee base. The inability of the Corporation to effectively deal with this integration and growth could have a material adverse impact on its business, financial condition, results of operations and prospects.

Risks Associated with Acquisitions and Dispositions

The Corporation considers acquisitions and dispositions of assets in the ordinary course of business. Typically, once an acquisition opportunity is identified, a review of available information relating to the assets is conducted. There is a risk that even a detailed review of records and assets may not necessarily reveal every existing or potential problem, nor will it permit the Corporation to become sufficiently familiar with the assets to fully assess their deficiencies and potential. There is no guarantee that defects in the chain of title will not arise to defeat the Corporation's title to certain assets or that environmental defects, liabilities or deficiencies do not exist or are greater than anticipated. Inspections may not always be performed on every well, and environmental problems, such as ground water contamination, are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the Corporation may assume certain environmental and other risk liabilities in connection with acquired assets.

In addition, acquisitions of oil and natural gas properties or companies are based in large part on engineering, environmental and economic assessments. These assessments include a series of assumptions regarding such factors as recoverability and marketability of oil and natural gas, environmental restrictions and prohibitions regarding releases and emissions of various substances, future prices of oil and natural gas, future operating costs, future capital expenditures and royalties and other government levies which will be imposed over the producing life of the reserves. Many of these factors are subject to change and are beyond the control of the Corporation. All such assessments involve a measure of geologic, engineering, environmental and regulatory uncertainty that could result in lower production and reserves or higher operating or capital expenditures than anticipated.

Achieving the benefits of acquisitions depends on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner and the Corporation's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Corporation. The integration of acquired businesses and assets may require substantial management effort, time and resources, diverting management's focus away from other strategic opportunities and operational matters.

Management continually assesses the value and contribution of the various assets within its portfolio. In this regard, certain assets may be periodically disposed of so the Corporation can focus its efforts and resources more efficiently. Depending on the state of the market for such assets, there is a risk that certain assets of the Corporation could realize less on disposition than what the market may expect for such disposition or realize less than their carrying value on the Corporation's financial statements.

Information Technology Systems and Cyber-Security

The Corporation has become increasingly dependent upon the availability, capacity, reliability and security of its information technology infrastructure and its ability to expand and continually update this infrastructure to conduct daily operations. The Corporation depends on various information technology systems to estimate reserves, process and record financial data, manage its financial resources and land base, analyze seismic information, administer its contracts with its operators and lessees and communicate with employees and third-party partners.

In the event the Corporation is unable to regularly deploy software and hardware, effectively upgrade systems and network infrastructure and take other steps to maintain or improve the efficiency and efficacy of its information technology systems, the operation of such systems could be interrupted or result in the loss, corruption or release of data. Further, the Corporation is subject to a variety of information technology and system risks as a part of its normal course operations, including potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach, and destruction or interruption of the Corporation's information technology systems by third parties or insiders. Unauthorized access to these systems by employees or third parties could lead to corruption or exposure of confidential, fiduciary or proprietary information, interruption to communications or operations or disruption to its business activities or its competitive position. In addition, cyber-phishing attempts, in which a malicious party attempts to obtain sensitive information such as usernames, passwords, and credit card details (and money) by disguising as a trustworthy entity in an electronic communication, have become more widespread and sophisticated in recent years. If the Corporation becomes a victim to a cyber-phishing attack it could result in a loss or theft of the Corporation's financial resources or critical data and information or could result in a loss of control of the Corporation's technological infrastructure or financial resources. The Corporation's employees are often the targets of such cyber-phishing attacks, as they are and will continue to be targeted by parties using fraudulent "spoof" emails to misappropriate information or to introduce viruses or other malware through "trojan horse" programs to the Corporation's computers. These emails appear to be legitimate emails, but direct recipients to fake websites operated by the sender of the email or request recipients to send a password or other confidential information through email or to download malware.

In addition to the oversight provided by the Corporation's Information Technology Committee, there is further reporting on the Corporation's information technology and cyber-security risks to the Board. Further, the Corporation maintains policies and procedures that address and implement employee protocols with respect to electronic communications and electronic devices and the Corporation periodically conducts cyber-security risk assessments. The Corporation also employs encryption protection for some of its confidential information. Despite the Corporation's efforts to mitigate such phishing attacks through education and training, phishing activities remain a serious problem that may damage its information technology infrastructure. The Corporation applies technical and process controls in line with industry-accepted standards to protect its information assets and systems, including a written incident response plan for responding to a cyber-security incident. However, these controls may not adequately prevent cyber-security breaches. Disruption of critical information technology services, or breaches of information security, could have a negative effect on the Corporation's performance and earnings, as well as on its reputation, and any damages sustained may not be adequately covered by the Corporation's current insurance coverage, or at all. The significance of any such event is difficult to quantify, but may in certain circumstances be material and could have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

To date, the Corporation has not been subject to a cyber-security attack or other breach that has had a material impact on its business or operations or resulted in material losses to the Corporation; however, there is no assurance that the measures the Corporation takes to protect its business systems and operational control systems will be effective in protecting against a breach in the future and that the Corporation will not incur such losses in the future.

Insurance

Although the Corporation maintains insurance in accordance with industry standards to address certain risks, such insurance has limitations on liability and may not be sufficient to cover the full extent of liabilities. In addition, certain risks are not, in all circumstances, insurable or, in certain circumstances, the Corporation may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of any uninsured liabilities would reduce the funds available to the Corporation. The occurrence of a significant event that the Corporation is not fully insured against, or the insolvency of the insurer of such event, could have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Litigation

In the normal course of the Corporation's operations, it may become involved in, be named as a party to or be the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions. Such proceedings may develop in relation to personal injury (including claims resulting from exposure to hazardous substances), property damage, property taxes, land and access rights, royalty rights, the environment (including claims relating to contamination) and lease and contractual disputes. The outcome of outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to the Corporation and, as a result, could have a material adverse effect on the Corporation's assets, liabilities, business, financial condition and results of operations. Even if the Corporation prevails in any such legal proceedings, the proceedings could be costly and time-consuming and may divert the attention of management and key personnel from the Corporation's business operations, which may adversely affect the Corporation.

Due to the rapid development of oil and natural gas technology, the Corporation may become involved in, be named as a party to or be the subject of, various legal proceedings in which it is alleged that the Corporation has infringed the intellectual property rights of others or conversely, the Corporation may commence lawsuits against others who the Corporation believes are infringing upon its intellectual property rights. The Corporation's involvement in intellectual property litigation could result in significant expense, adversely affecting the development of its assets or intellectual property or diverting the efforts of its technical and management personnel, whether or not such litigation is resolved in the Corporation's favour. In the event of an adverse outcome as a defendant in any such litigation, the Corporation may, among other things, be required to: (i) pay substantial damages; (ii) cease the use of infringing intellectual property; (iii) expend significant resources to develop or acquire non-infringing intellectual property; (iv) discontinue processes incorporating infringing technology; or (v) obtain licences to the infringing intellectual property. However, the Corporation may not be successful in such development or acquisition or such licences may not be available on reasonable terms. Any such development, acquisition or licence could require the expenditure of substantial time and other resources and could have a material adverse effect on the Corporation's business and financial results.

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights in portions of Western Canada. The Corporation is not aware that any claims have been made in respect of its properties or assets; however, the legal basis of an aboriginal land claim and aboriginal rights is a matter of considerable legal complexity and the impact of the assertion of such a claim, or the possible effect of a settlement of such claim, upon the Corporation cannot be predicted with any degree of certainty at this time. In addition, no assurance can be given that any recognition of aboriginal rights or claims whether by way of a negotiated settlement or by judicial pronouncement (or through the grant of an injunction prohibiting exploration or development activities pending resolution of any such claim) would not delay or even prevent the Corporation's exploration and development activities. If a claim arose and was successful, such claim may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In addition, the process of addressing such claims, regardless of the outcome, is expensive and time consuming and could result in delays which could have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Internal Controls

Effective internal controls are necessary for the Corporation to provide reliable financial reports and to help prevent fraud. Although the Corporation undertakes a number of procedures in order to help ensure the reliability of its financial reports, including those imposed on it under Canadian securities laws, the Corporation cannot be certain that such measures will ensure that the Corporation will maintain adequate control over financial processes and reporting. Failure to implement required new or improved controls, or difficulties encountered in their implementation, could harm the Corporation's results of operations or cause it to fail to meet its reporting obligations. If the Corporation or its independent auditors discover a material weakness, the disclosure of that fact, even if quickly remedied, could reduce the market's confidence in the Corporation's financial statements and harm the trading prices of the Corporation's securities.

Title to Assets

The Corporation's actual title to and interest in its properties, and its right to produce and sell the oil and natural gas therefrom, may vary from the Corporation's records. In addition, there may be valid legal challenges or legislative changes that affect the Corporation's title to and right to produce from its oil and natural gas properties, which could impair the Corporation's activities on them and result in a reduction of the revenue received by the Corporation.

If a defect exists in the chain of title or in the Corporation's right to produce, or a legal challenge or legislative change arises, it is possible that the Corporation may lose all or a portion of the properties to which the title defect relates and/or its right to produce from such properties. This may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Breaches of Confidentiality

While discussing potential business relationships or other transactions with third parties, the Corporation may disclose confidential information relating to the business, operations or affairs of the Corporation. Although confidentiality agreements are generally signed by third parties prior to the disclosure of any confidential information, a breach could put the Corporation at competitive risk and may cause significant damage to its business. The harm to the Corporation's business from a breach of confidentiality cannot presently be quantified, but may be material and may not be compensable in damages. There is no assurance that, in the event of a breach of confidentiality, the Corporation will be able to obtain equitable remedies, such as injunctive relief, from a court of competent jurisdiction in a timely manner, if at all, in order to prevent or mitigate any damage to its business that such a breach of confidentiality may cause.

Income Taxes

The Corporation files all required income tax returns and believes that it is in full compliance with the provisions of the *Income Tax Act* (Canada) and all other applicable provincial tax legislation. However, such returns are subject to reassessment by the applicable taxation authority. In the event of a successful reassessment of the Corporation, such reassessment may have an impact on current and future taxes payable.

Income tax laws relating to the oil and natural gas industry, such as the treatment of resource taxation or dividends, may in the future be changed or interpreted in a manner that adversely affects the Corporation. Furthermore, tax authorities having jurisdiction over the Corporation may disagree with how the Corporation calculates its income for tax purposes or could change administrative practices to the Corporation's detriment.

Negative Impact of Additional Sales or Issuances of Securities

The Corporation may issue an unlimited number of Common Shares without any vote or action by the shareholders, subject to the rules of any stock exchange on which the Corporation's securities may be listed. The Corporation may make future acquisitions or enter into financings or other transactions involving the issuance of securities of the Corporation which may be dilutive. If the Corporation issues additional securities, the percentage ownership of existing shareholders will be reduced and diluted and the price of the Corporation's securities could decrease.

Additional Taxation Applicable to Non-Residents

Tax legislation in Canada may impose withholding or other taxes on the cash dividends, stock dividends or other property transferred by the Corporation to non-resident shareholders. These taxes may be reduced pursuant to tax treaties between Canada and the non-resident shareholder's jurisdiction of residence. Evidence of eligibility for a reduced withholding rate must be filed by the non-resident shareholder in prescribed form with their broker (or in the case of registered shareholders, with the transfer agent). In addition, the country in which the non-resident shareholder is resident may impose additional taxes on such dividends. Any of these taxes may change from time to time.

Foreign Exchange Risk for Non-Resident Shareholders

The Corporation's cash dividends are declared in Canadian dollars and may be converted in certain instances to foreign denominated currencies at the spot exchange rate at the time of payment. As a consequence, non-resident shareholders and shareholders who calculate their return in currencies other than the Canadian dollar are subject to foreign exchange risk. To the extent that the Canadian dollar strengthens with respect to their currency, the amount of any dividend will be reduced when converted to their home currency.

Conflicts of Interest

Certain directors or officers of the Corporation may also be directors or officers of other oil and natural gas companies and as such may, in certain circumstances, have a conflict of interest. Conflicts of interest, if any, will be subject to and governed by procedures prescribed by the ABCA which require a director or officer of a Corporation who is a party to, or is a director or an officer of, or has a material interest in any person who is a party to, a material contract or proposed material contract with the Corporation to disclose his or her interest and, in the case of directors, to refrain from voting on any matter in respect of such contract unless otherwise permitted under the ABCA. See *"Directors and Officers – Conflicts of Interest".*

Forward-Looking Information May Prove Inaccurate

Shareholders and prospective investors are cautioned not to place undue reliance on the Corporation's forward-looking statements. By their nature, forward-looking statements involve numerous assumptions and known and unknown risks and uncertainties, of both a general and specific nature, that could cause actual results to differ materially from those suggested by the forward-looking statements or contribute to the possibility that predictions, forecasts or projections will prove to be materially inaccurate. Additional information on the risks, assumptions and uncertainties relating to forward-looking statements is found under the heading *"Special Notes to Reader – Forward-Looking Statements"*.

DIVIDEND AND DISTRIBUTION POLICY

Common Shares

On November 9, 2016, the Board approved a quarterly dividend policy in respect of the Common Shares. This dividend policy establishes that until changed by the Board, cash dividends will be paid to the holders of Common Shares for the quarters ending March 31, June 30, September 30 and December 31. The payment date for any dividend declared shall be the last day of March, June, September and December; provided that, if any such date is not a business day, the payment date shall be the next business day. The record date for determining the shareholders entitled to receive dividends is expected to be on or about the 15^{th} day of the last month of the applicable quarter. The first quarterly dividend under this policy was paid in respect of the quarter ended March 31, 2017. The dividend policy is periodically reviewed by the Board and no assurance or guarantee can be given that Birchcliff will maintain the dividend policy in its current form.

Birchcliff does not have a dividend reinvestment plan or stock dividend program.

Preferred Shares – Series A and Series C Preferred Shares

The Corporation has Series A Preferred Shares and Series C Preferred Shares outstanding, on which dividends have been paid to their holders in accordance with their terms. See *"Description of Capital Structure – Preferred Shares".*

Dividend History

The following table sets forth details regarding the cash dividends that were declared on the Common Shares, the Series A Preferred Shares and the Series C Preferred Shares during the three most recently completed financial years:

Declaration Date	Record Date	Payment Date	Type	Amount ($)
Common Shares				
November 28, 2018	December 17, 2018	December 31, 2018	Quarterly, Cash	0.025
September 5, 2018	September 17, 2018	October 1, 2018	Quarterly, Cash	0.025
May 29, 2018	June 15, 2018	July 3, 2018	Quarterly, Cash	0.025
February 28, 2018	March 15, 2018	April 2, 2018	Quarterly, Cash	0.025
November 30, 2017	December 15, 2017	January 2, 2018	Quarterly, Cash	0.025
September 5, 2017	September 15, 2017	October 2, 2017	Quarterly, Cash	0.025
May 30, 2017	June 15, 2017	June 30, 2017	Quarterly, Cash	0.025
March 1, 2017	March 15, 2017	March 31, 2017	Quarterly, Cash	0.025
Series A Preferred Shares				
November 28, 2018	December 17, 2018	December 31, 2018	Quarterly, Cash	0.523375
September 5, 2018	September 17, 2018	October 1, 2018	Quarterly, Cash	0.523375
May 29, 2018	June 15, 2018	July 3, 2018	Quarterly, Cash	0.523375
February 28, 2018	March 15, 2018	April 2, 2018	Quarterly, Cash	0.523375
November 30, 2017	December 15, 2017	January 2, 2018	Quarterly, Cash	0.523375
September 5, 2017	September 15, 2017	October 2, 2017	Quarterly, Cash	0.50
May 30, 2017	June 15, 2017	June 30, 2017	Quarterly, Cash	0.50
March 1, 2017	March 15, 2017	March 31, 2017	Quarterly, Cash	0.50
November 30, 2016	December 15, 2016	January 3, 2017	Quarterly, Cash	0.50
September 1, 2016	September 15, 2016	September 30, 2016	Quarterly, Cash	0.50
May 31, 2016	June 15, 2016	June 30, 2016	Quarterly, Cash	0.50
March 3, 2016	March 16, 2016	March 31, 2016	Quarterly, Cash	0.50
Series C Preferred Shares				
November 28, 2018	December 17, 2018	December 31, 2018	Quarterly, Cash	0.4375
September 5, 2018	September 17, 2018	October 1, 2018	Quarterly, Cash	0.4375
May 29, 2018	June 15, 2018	July 3, 2018	Quarterly, Cash	0.4375
February 28, 2018	March 15, 2018	April 2, 2018	Quarterly, Cash	0.4375
November 30, 2017	December 15, 2017	January 2, 2018	Quarterly, Cash	0.4375
September 5, 2017	September 15, 2017	October 2, 2017	Quarterly, Cash	0.4375
May 30, 2017	June 15, 2017	June 30, 2017	Quarterly, Cash	0.4375
March 1, 2017	March 15, 2017	March 31, 2017	Quarterly, Cash	0.4375
November 30, 2016	December 15, 2016	January 3, 2017	Quarterly, Cash	0.4375
September 1, 2016	September 15, 2016	September 30, 2016	Quarterly, Cash	0.4375
May 31, 2016	June 15, 2016	June 30, 2016	Quarterly, Cash	0.4375
March 3, 2016	March 16, 2016	March 31, 2016	Quarterly, Cash	0.4375

On February 13, 2019, the Board declared the following dividends for the quarter ending March 31, 2019: (i) a cash dividend of $0.02625 per share on the Common Shares; (ii) a cash dividend of $0.523375 per share on the Series A Preferred Shares; and (iii) a cash dividend of $0.4375 per share on the Series C Preferred Shares. The dividends are payable on April 1, 2019 to shareholders of record at the close of business on March 15, 2019.

The declaration and payment of dividends is subject to the discretion of the Board and may vary depending on a variety of factors and conditions existing from time to time. The payment of cash dividends to shareholders is not assured or guaranteed and dividends may be reduced or suspended. In addition to the foregoing, the Corporation's ability to pay dividends now or in the future may be limited by covenants contained in the agreements governing any indebtedness that the Corporation has incurred or may incur in the future, including the terms of the Credit Facilities. The Credit Facilities provide that Birchcliff is not permitted to make any distribution (including dividends) at any time when an event of default exists or would reasonably be expected to exist upon making such distribution, unless such event of default arose subsequent to the ordinary course declaration of the applicable distribution. For further information regarding the risks and assumptions relating to the payment of dividends, see *"Risk Factors – Financial Risks and Risks Relating to Economic Conditions – Dividends"*.

DESCRIPTION OF CAPITAL STRUCTURE

Authorized Share Capital and Securities Outstanding

The authorized share capital of the Corporation consists of an unlimited number of Common Shares and an unlimited number of Preferred Shares, each without par value. In addition, the Corporation also has Performance Warrants and Options that are outstanding which are exercisable into Common Shares.

The following table sets forth the securities of the Corporation that were outstanding at December 31, 2018:

Authorized Securities Outstanding	Number of Securities
Common Shares	265,911,362
Series A Preferred Shares	2,000,000
Series C Preferred Shares	2,000,000
Performance Warrants	2,939,732
Options	15,847,570

The following is a summary of the rights, privileges, restrictions and conditions which attach to the Common Shares and the Preferred Shares as a class:

Common Shares

Shareholders are entitled to receive notice of, to attend and to one vote per Common Share at all meetings of holders of Common Shares, except meetings at which only holders of a specified class of shares are entitled to vote. Shareholders are entitled to receive any dividend declared by the Corporation on the Common Shares; provided that the Corporation shall be entitled to declare dividends on the Preferred Shares or on any of such classes of shares without being obliged to declare any dividends on the Common Shares. Subject to the rights, privileges, restrictions and conditions attaching to any other class of shares of the Corporation, holders of Common Shares are entitled to receive the remaining property of the Corporation upon dissolution in equal rank with the holders of other Common Shares.

On November 15, 2017, the Corporation announced that the TSX had accepted the Corporation's notice of intention to make a normal course issuer bid pursuant to which the Corporation could purchase for cancellation up to 20,121,747 of its outstanding Common Shares. This normal course issuer bid commenced on November 20, 2017 and terminated on November 19, 2018. No Common Shares were purchased or cancelled during this period.

On November 20, 2018, the Corporation announced that the TSX had accepted the Corporation's notice of intention to make a normal course issuer bid pursuant to which the Corporation could purchase for cancellation up to 18,767,520 of its outstanding Common Shares. This normal course issuer bid commenced on November 23, 2018 and will terminate on November 22, 2019, or such earlier time as the bid is completed or terminated at the option of the Corporation. The actual number of Common Shares purchased pursuant to the bid and the timing of such purchases will be determined by Birchcliff and is dependent on future market conditions. All Common Shares purchased under the bid will be cancelled. As of the date hereof, the Corporation has not purchased any Common Shares under the bid.

Preferred Shares

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

The Preferred Shares of each series shall, with respect to the payment of dividends and the distribution of assets or return of capital in the event of liquidation, dissolution or winding up of the Corporation, whether voluntary or involuntary, or any other return of capital or distribution of the assets of Birchcliff amongst its shareholders for the purpose of winding up its affairs, be entitled to preference over the Common Shares and over any other shares of the Corporation ranking by their terms junior to the Preferred Shares of that series. The Preferred Shares of any series may also be given such other preferences, not inconsistent with the articles of the Corporation, over the Common Shares and any other Preferred Shares as may be fixed by the Board.

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

In the event of the liquidation, dissolution or winding-up of the Corporation, the holders of Series A Preferred Shares, Series B Preferred Shares and Series C Preferred Shares are entitled to receive $25.00 per share plus all accrued and unpaid dividends thereon, before any amount is paid or any property or assets are distributed to holders of the Common Shares.

<u>Series A Preferred Shares and Series B Preferred Shares</u>

The Series A Preferred Shares and the Series B Preferred Shares are identical in all material respects other than different dividend rights, redemption rights and conversion rights attached thereto. There are currently no Series B Preferred Shares outstanding.

On August 8, 2012, the Corporation issued an aggregate of 2,000,000 Series A Preferred Shares. The holders of the outstanding Series A Preferred Shares are entitled to receive, as and when declared by the Board, fixed cumulative preferential cash dividends, payable quarterly. The dividend rate of the Series A Preferred Shares reset on September 30, 2017 and will reset every five years thereafter at a rate equal to the then current five-year Government of Canada bond yield plus 6.83%. The dividend rate for the initial period from and including the date of issue to, but excluding, September 30, 2017, was $2.00 per share per year. The dividend rate for the five-year period from and including September 30, 2017 to, but excluding September 30, 2022, is 8.374%.

The Series A Preferred Shares were redeemable by the Corporation on September 30, 2017 and are redeemable by the Corporation on September 30 in every fifth year thereafter, at a redemption price of $25.00 per share, plus all accrued and unpaid dividends.

The holders of the Series A Preferred Shares had the right to convert their shares into an equal number of Series B Preferred Shares on September 30, 2017, subject to certain conditions being met. On August 14, 2017, the Corporation announced it did not intend to exercise its right to redeem the Series A Preferred Shares on September 30, 2017. As a result, the holders of the Series A Preferred Shares had the right to choose to retain any or all of their Series A Preferred Shares and continue to receive a fixed rate quarterly dividend or to convert, on a one-for-one basis, any or all of their Series A Preferred Shares into Series B Preferred Shares and receive a floating rate quarterly dividend. On September 18, 2017, the Corporation announced that the holders of the Series A Preferred Shares were not entitled to convert their Series A Preferred Shares into Series B Preferred Shares as only 165,960 Series A Preferred Shares had been tendered for conversion, which was less than the 250,000 shares required to give effect to the conversion. As a result, none of Birchcliff's outstanding Series A Preferred Shares were converted into Series B Preferred Shares on September 30, 2017. Subject to redemption by the Corporation, holders of the Series A Preferred Shares will have the opportunity to convert their shares into Series B Preferred Shares again on September 30, 2022, and every five years thereafter as long as the shares remain outstanding.

<u>Series C Preferred Shares</u>

On June 14, 2013, the Corporation issued 2,000,000 Series C Preferred Shares. The holders of the outstanding Series C Preferred Shares are entitled to receive, as and when declared by the Board, fixed cumulative preferential cash dividends at an annual rate of $1.75 per share, payable quarterly. The Series C Preferred Shares are redeemable by the Corporation on and after June 30, 2018 at a redemption price of $25.75 per share if redeemed before June 30, 2019, at a redemption price of $25.50 per share if redeemed on or after June 30, 2019 but before June 30, 2020 and at a redemption price of $25.00 per share if redeemed on or after June 30, 2020, in each case together with all accrued and unpaid dividends.

On and after June 30, 2020, the holders of Series C Preferred Shares may redeem their shares for cash on the last day of March, June, September and December of each year at $25.00 per share, together with all accrued and unpaid dividends. Upon receipt of a notice of redemption from the holder, the Corporation may elect to convert such Series C Preferred Shares into Common Shares. The number of Common Shares into which each Series C Preferred Share may be so converted will be determined by dividing the amount of $25.00 together with all accrued and unpaid dividends by the greater of $2.00 and 95% of the weighted average trading price of the Common Shares on the TSX for a period of 20 consecutive trading days ending on the fourth day prior to the date specified for conversion (the "**Current Market Price**"). In addition, on and after June 30, 2018, the Corporation may convert the outstanding Series C Preferred Shares into Common Shares. The number of Common Shares into which each Series C Preferred Share may be so converted will be determined by dividing the then applicable redemption price, together with all accrued and unpaid dividends, by the greater of $2.00 and 95% of the Current Market Price. Any conversion of the Series C Preferred Shares will be subject to the approval of the TSX, if required.

Performance Warrants

Performance Warrants were granted to the executive officers of the Corporation at the Corporation's inception and were designed to act as a long-term retention incentive for the holders thereof. As a performance-based incentive, the Performance Warrants were not exercisable unless the trading price of the Common Shares exceeded $6.00 (being the trading price that is equal to at least two times the exercise price of $3.00) for a period of 20 consecutive trading days. This condition was satisfied in November of 2005 and accordingly, all of the Performance Warrants have been exercisable since November 2005. The outstanding Performance Warrants are held by Messrs. Tonken, Geremia, Surbey and Bosman, each of whom is an executive officer and/or director of the Corporation. On May 15, 2014, the holders of Common Shares approved an amendment to the outstanding Performance Warrants to extend the expiry date of such Performance Warrants from January 31, 2015 to January 31, 2020.

Options

Pursuant to the Stock Option Plan, Options may be granted from time to time to the directors, officers, employees and certain service providers of the Corporation. Options are granted by the Board who, at the time of the grant, fixes the exercise price, vesting dates and the expiry date of such Options. The aggregate number of Common Shares issuable under Options that are issued and outstanding at any time under the Stock Option Plan shall not exceed 10% of the aggregate number of Common Shares issued and outstanding at that time, as determined on a non-diluted basis.

The Stock Option Plan provides that the expiry date of an Option shall be no later than 10 years from the date of grant of such Option and that the exercise price of an Option shall be determined by the Board but shall not be lower than the higher of: (i) the closing price of the Common Shares on the TSX on the first trading day immediately preceding the date of grant; or (ii) the lowest price permitted by the TSX. All of the Options granted to date under the Stock Option Plan provide for: (i) the expiry of such Options not later than the fifth anniversary of the date of grant; and (ii) the vesting of such Options with respect to one-third of the Common Shares issuable thereunder on each of the first, second and third anniversaries of the date of grant.

Credit Facilities

The Corporation has extendible revolving credit facilities in the aggregate principal amount of $950 million (the "**Credit Facilities**") which are comprised of an extendible revolving syndicated term credit facility of $850 million (the "**Syndicated Credit Facility**") and an extendible revolving working capital facility of $100 million (the "**Working Capital Facility**"). The Credit Facilities allow for prime rate loans, LIBOR loans, U.S. base rate loans, bankers' acceptances and, in the case of the Working Capital Facility only, letters of credit. The maturity date of each of the Syndicated Credit Facility and the Working Capital Facility is currently May 11, 2021. The Corporation may each year, at its option, request an extension to the maturity date of the Syndicated Credit Facility and the Working Capital Facility, or either of them, for an additional period of up to three years from May 11 of the year in which the extension request is made. The Credit Facilities are subject to semi-annual reviews of the borrowing base limit by the Corporation's syndicate of lenders, which are typically completed in May and November of each year. The Credit Facilities do not contain any financial maintenance covenants. For further information regarding the Credit Facilities, see the Corporation's audited annual financial statements and related management's discussion and analysis for the year ended December 31, 2018. See *"Risk Factors – Financial Risks and Risks Relating to Economic Conditions – Credit Facilities"*.

MARKET FOR SECURITIES

Trading Price and Volume

The Common Shares, the Series A Preferred Shares and the Series C Preferred Shares are listed for trading on the TSX under the trading symbols "BIR", "BIR.PR.A" and "BIR.PR.C", respectively. The following table sets forth the price ranges and volumes of each class of securities of the Corporation that were traded on the TSX during the year ended December 31, 2018:

	Common Shares			Series A Preferred Shares			Series C Preferred Shares		
Month	**High ($)**	**Low ($)**	**Monthly Trading Volume**	**High ($)**	**Low ($)**	**Monthly Trading Volume**	**High ($)**	**Low ($)**	**Monthly Trading Volume**
January	4.57	3.16	60,678,875	25.93	21.67	124,874	24.98	22.05	67,217
February	3.53	2.93	41,678,030	24.30	22.80	45,828	23.65	23.00	22,554
March	4.04	2.90	51,233,797	24.62	23.46	28,349	24.47	23.50	15,060
April	4.69	3.645	56,973,097	25.50	24.25	36,642	25.05	24.40	17,442
May	4.92	4.11	36,755,663	25.78	25.15	26,615	25.30	24.69	39,910
June	4.93	4.15	30,955,587	25.60	25.20	21,364	25.18	25.00	15,645
July	5.45	4.61	30,464,084	25.99	25.30	28,090	25.20	24.93	27,063
August	5.34	4.67	19,706,276	26.38	25.71	33,289	25.66	25.07	40,861
September	5.37	4.155	20,684,427	26.50	25.89	26,210	25.52	24.91	14,080
October	5.44	4.01	24,258,151	26.42	25.45	31,399	25.61	25.00	11,133
November	4.64	3.45	25,162,701	26.49	25.75	11,530	25.25	24.72	17,988
December	3.99	2.57	39,113,085	26.01	24.20	19,065	25.18	23.51	21,187

Prior Sales

During the year ended December 31, 2018, the only securities the Corporation issued which are outstanding but are not listed or quoted on a marketplace were an aggregate of 4,734,900 Options which were granted at exercise prices ranging from $3.07 to $5.20 per Common Share.

ESCROWED SECURITIES AND SECURITIES SUBJECT TO CONTRACTUAL RESTRICTION ON TRANSFER

To the Corporation's knowledge, at December 31, 2018, no securities of Birchcliff were held in escrow or subject to a contractual restriction on transfer.

DIRECTORS AND OFFICERS

Directors

The following table sets forth for each person who is a director of the Corporation at the date hereof: (i) their name, province and country of residence and whether they are independent; (ii) the period during which they have served as a director of the Corporation or its predecessor entities; and (iii) their principal occupation during the past five years or more:

Name, Province and Country of Residence	Director Since	Principal Occupation During the Past Five Years or More
Dennis A. Dawson(1)(2)(3)(4) *Alberta, Canada* Independent	May 14, 2015	Mr. Dawson is a director of Birchcliff, is the independent Lead Director and is the Chair of the Compensation Committee and the Nominating Committee. He has over 32 years of oil and natural gas experience, including nine years as General Counsel for Pan-Alberta Gas Ltd., a major Canadian natural gas export and marketing company. Mr. Dawson was the Vice-President, General Counsel and Corporate Secretary of AltaGas from December 1998 until April 2015. He first joined AltaGas as Associate General Counsel in August 1997, after consulting with AltaGas Services Inc. from July 1996. Effective July 1998, Mr. Dawson became AltaGas' General Counsel and Corporate Secretary and effective December 1998, he became Vice-President, General Counsel and Corporate Secretary. He received a Bachelor of Arts degree from the University of Lethbridge and a Bachelor of Laws degree from the University of Alberta.
Debra A. Gerlach(1)(2)(3)(4) *Alberta, Canada* Independent	November 8, 2017	Ms. Gerlach is a director of Birchcliff and is the Chair of the Audit Committee. From September 1996 until September 2017, Ms. Gerlach was a partner with Deloitte LLP where she practiced in the Assurance and Advisory group. Prior thereto, she held various positions within Deloitte LLP from the time she joined the firm in August 1982. During her 35 year career with the firm, Ms. Gerlach worked with numerous public oil and gas companies. Ms. Gerlach is a Chartered Accountant with the Chartered Professional Accountants of Alberta and received a Bachelor of Commerce degree and a Master of Business Administration degree from the University of Calgary.
Stacey E. McDonald(1)(2)(3)(4) *Alberta, Canada* Independent	December 14, 2018	Ms. McDonald is a director of Birchcliff and has over 13 years of experience in the energy and financial sectors. From September 2016 to July 2018, Ms. McDonald was a Managing Director – Institutional Equity Research (Energy) at GMP FirstEnergy and its predecessor, GMP Securities, independent global investment banks. She joined GMP Securities in February 2006 as a research associate and began publishing independently as an Equity Analyst in 2009. Ms. McDonald received a Bachelor of Commerce degree in Finance from the University of Alberta.

Name, Province and Country of Residence	Director Since	Principal Occupation During the Past Five Years or More
James W. Surbey[3] *Alberta, Canada* Non-independent	May 11, 2017	Mr. Surbey is a director of Birchcliff and is the Chair of the Reserves Evaluation Committee. He is also an employee of Birchcliff and an independent businessman. Mr. Surbey has over 41 years of experience in the oil and natural gas industry and is one of the Corporation's founders. He was the Vice-President, Corporate Development and Corporate Secretary of Birchcliff from the inception of the Corporation until June 30, 2017. Prior to joining Birchcliff, he served as the Vice-President, Corporate Development of Case Resources Inc., the Senior Vice-President, Corporate Development of Big Bear Exploration Ltd. and the Vice-President, Corporate Development of Stampeder Exploration Ltd. Mr. Surbey was previously a senior partner of the law firm Howard Mackie (now Borden Ladner Gervais LLP). He received a Bachelor of Engineering degree and a Bachelor of Laws degree from McGill University and is a member of the Law Society of Alberta.
A. Jeffery Tonken *Alberta, Canada* Chairman of the Board Non-independent	July 6, 2004	See Mr. Tonken's biography under *"Executive Officers".*

(1) Member of the Audit Committee.
(2) Member of the Compensation Committee.
(3) Member of the Reserves Evaluation Committee.
(4) Member of the Nominating Committee.

The directors of the Corporation hold office until the close of the next annual meeting of shareholders of the Corporation or until their successors are elected or appointed. The next annual meeting of the shareholders of the Corporation is scheduled for May 16, 2019.

Executive Officers

The following table sets forth for each person who is an executive officer of the Corporation at the date hereof: (i) their name, province and country of residence; (ii) their position with the Corporation; and (iii) their principal occupation during the past five years or more:

Name and Province and Country of Residence	Current Position with Birchcliff	Principal Occupation During the Past Five Years or More
A. Jeffery Tonken *Alberta, Canada*	Chairman of the Board and President and Chief Executive Officer	Mr. Tonken has been the President and Chief Executive Officer and a director of Birchcliff since the inception of the Corporation and the Chairman of the Board since May 11, 2017. He has over 38 years of experience in the oil and natural gas industry and is one of the Corporation's founders. Prior to Birchcliff, Mr. Tonken founded and served as the President and Chief Executive Officer of Case Resources Inc., Big Bear Exploration Ltd. and Stampeder Exploration Ltd. He was previously a partner of the law firm Howard, Mackie (now Borden Ladner Gervais LLP). Mr. Tonken is also the Vice-Chair of the Board of Governors of the Canadian Association of Petroleum Producers (CAPP). He received a Bachelor of Commerce degree from the University of Alberta and a Bachelor of Laws degree from the University of Wales and is a member of the Law Society of Alberta.
Myles R. Bosman *Alberta, Canada*	Vice-President, Exploration and Chief Operating Officer	Mr. Bosman has been the Vice-President, Exploration and Chief Operating Officer of Birchcliff since the inception of the Corporation. He is a Professional Geologist with over 28 years of experience in the oil and natural gas industry and is one of the Corporation's founders. Prior to joining Birchcliff, Mr. Bosman served as the Vice-President, Exploration and Chief Operating Officer of Case Resources Inc., the Exploration Manager of Summit Resources Ltd. and as an Exploration Geologist with both Numac Energy Inc. and Canadian Hunter Exploration. He received a Bachelor of Science degree in Geology from the University of Calgary and a Resource Engineering diploma from the Northern Alberta Institute of Technology and is a member of APEGA.
Christopher A. Carlsen *Alberta, Canada*	Vice-President, Engineering	Mr. Carlsen has been the Vice-President, Engineering of Birchcliff since July 22, 2013 and prior thereto, he was an Asset Team Lead and Senior Exploitation Engineer with Birchcliff. He is a Professional Engineer with over 18 years of experience in the oil and natural gas industry. Prior to joining Birchcliff, Mr. Carlsen was the Senior Engineer at Greenfield Resources Ltd. and held various engineering positions at both Encana Corporation and PanCanadian Petroleum Ltd. He received a Bachelor of Science degree in Chemical Engineering from the University of Saskatchewan and is a member of APEGA.

Name and Province and Country of Residence	Current Position with Birchcliff	Principal Occupation During the Past Five Years or More
Bruno P. Geremia *Alberta, Canada*	Vice-President and Chief Financial Officer	Mr. Geremia has been the Vice-President and Chief Financial Officer of Birchcliff since the inception of the Corporation. He is a Chartered Accountant with over 27 years of experience in the oil and natural gas industry and is one of the Corporation's founders. Prior to joining Birchcliff, Mr. Geremia served as the Vice-President and Chief Financial Officer of both Case Resources Inc. and Big Bear Exploration Ltd., as the Director, Commercial of Gulf Canada Resources and as the Manager, Special Projects of Stampeder Exploration Ltd. He was previously a Chartered Accountant with Deloitte & Touche LLP. Mr. Geremia received a Bachelor of Commerce degree from the University of Calgary.
David M. Humphreys *Alberta, Canada*	Vice-President, Operations	Mr. Humphreys has been the Vice-President, Operations of Birchcliff since October 9, 2009 and has over 31 years of experience in the oil and natural gas industry. Prior to joining Birchcliff, he served as the Vice-President, Operations of Highpine Oil & Gas Ltd., White Fire Energy Ltd. and Virtus Energy Ltd. and the Production Manager of both Husky Oil Operations Ltd. and Ionic Energy. Mr. Humphreys received a Hydrocarbon Engineering Technology diploma from the Northern Alberta Institute of Technology and is a member of ASET. He also has his P.L. (Eng.) designation and is a member of APEGA.

Shareholdings of Directors and Executive Officers

At March 12, 2019: (i) the directors and executive officers of the Corporation, as a group, beneficially owned, or controlled or directed, directly or indirectly, 2,624,039 Common Shares, representing approximately 1% of the issued and outstanding Common Shares; and (ii) the executive officers of the Corporation, as a group, held Performance Warrants and Options to acquire a further 7,314,765 Common Shares.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

Except as disclosed below, none of the directors or executive officers of the Corporation is, as at the date of this Annual Information Form, or was within 10 years before the date of this Annual Information Form, a director, chief executive officer or chief financial officer of any company including the Corporation that: (i) was subject to a cease trade order, an order similar to a cease trade order or an order that denied the relevant company access to any exemption under securities legislation that was in effect for a period of more than 30 consecutive days (an "**Order**") that was issued while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer; or (ii) was subject to an Order that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer.

Except as disclosed below, none of the directors or executive officers of the Corporation or a shareholder holding a sufficient number of securities of the Corporation to affect materially the control of the Corporation: (i) is, as at the date of this Annual Information Form, or has been within the 10 years before the date of this Annual Information Form, a director or executive officer of any company including the Corporation that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; or (ii) has, within the 10 years before the date of this Annual Information Form, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director, executive officer or shareholder.

From July 8, 2010 to February 20, 2018, Mr. Geremia was a director of Manitok Energy Inc. ("**Manitok**"), a company listed on the TSX Venture Exchange. On January 10, 2018, Manitok announced that it had filed a Notice of an Intention to Make a Proposal (the "**NOI**") pursuant to the provisions of the BIA, naming FTI Consulting Canada Inc. ("**FTI**") as the proposed trustee. Manitok was unable to form a proposal with its creditors within 30 days after filing its NOI and as a result, on February 20, 2018, the Court of Queen's Bench of Alberta issued a Receivership Order placing Manitok into receivership and substituting Alvarez & Marsal Canada Inc. ("**Alvarez**") in place of FTI as the trustee in bankruptcy. The Court also appointed Alvarez as the receiver and manager of Manitok and terminated the NOI. All of the directors of Manitok, including Mr. Geremia, resigned. On May 4, 2018, a cease trade order was issued against Manitok under the securities legislation of Alberta and Ontario for failure to file annual audited financial statements and annual management's discussion and analysis for the year ended December 31, 2017.

None of the directors or executive officers of the Corporation or a shareholder holding a sufficient number of securities of the Corporation to affect materially the control of the Corporation has been subject to: (i) 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 (ii) any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

Conflicts of Interest

Directors and executive officers of the Corporation may invest in or become directors or officers of other oil and natural gas companies or entities that may provide financing to, or make equity investments in, competitors of the Corporation, which may give rise to conflicts of interest. Conflicts, if any, will be governed by the ABCA. Pursuant to the ABCA, directors and executive officers of the Corporation are required to disclose the nature and extent of any interest that they have in a material contract or material transaction, and in the case of a director, such director will refrain from voting on any matter in respect of such contract or transaction, unless otherwise provided by the ABCA.

AUDIT COMMITTEE

Audit Committee Charter

The Charter adopted by the Audit Committee of the Corporation is attached hereto as Appendix D.

Composition of the Audit Committee and Relevant Education and Experience

At the date hereof, the Audit Committee is comprised of Mr. Dennis A. Dawson, Ms. Debra A. Gerlach and Ms. Stacey E. McDonald. Ms. Gerlach is Chair of the Audit Committee. Each of the members of the Audit Committee is "independent" and "financially literate" within the meaning of NI 52-110. The following table sets forth the relevant education and experience of each member of the Audit Committee:

Name	Independent?	Financially Literate?	Relevant Education and Experience
Dennis A. Dawson	Yes	Yes	Mr. Dawson has over 32 years of oil and natural gas experience, including nine years as General Counsel for Pan-Alberta Gas Ltd., a major Canadian natural gas export and marketing company. Mr. Dawson was the Vice-President, General Counsel and Corporate Secretary of AltaGas from December 1998 until April 2015. He received a Bachelor of Arts degree from the University of Lethbridge and a Bachelor of Laws degree from the University of Alberta.
Debra A. Gerlach (Chair)	Yes	Yes	Ms. Gerlach was a partner with Deloitte LLP from September 1996 until September 2017, where she practiced in the Assurance and Advisory group. Prior thereto, she held various positions within Deloitte from the time she joined the firm in August 1982. During her 35 year career with the firm, Ms. Gerlach worked with numerous public oil and gas companies. Ms. Gerlach is a Chartered Accountant with the Chartered Professional Accountants of Alberta and received a Bachelor of Commerce degree and a Master of Business Administration degree from the University of Calgary.
Stacey E. McDonald	Yes	Yes	Ms. McDonald has over 13 years of experience in the energy and financial sectors. From September 2016 to July 2018, Ms. McDonald was a Managing Director – Institutional Equity Research (Energy) at GMP FirstEnergy and its predecessor, GMP Securities, independent global investment banks. Ms. McDonald joined GMP Securities in February 2006 as a research associate and began publishing independently as an Equity Analyst in 2009. Ms. McDonald received a Bachelor of Commerce degree in Finance from the University of Alberta.

Pre-Approval Policies and Procedures

The Charter adopted by the Audit Committee provides that all non-audit services to be provided to the Corporation by the Corporation's external auditor must be pre-approved by the Audit Committee. The Audit Committee may delegate this function to one of its independent members, who shall report to the Audit Committee on any such approvals.

External Auditor Service Fees

The following table summarizes the fees billed to the Corporation by its auditors, KPMG LLP, for external audit and other services:

Fees	2018	2017
Audit Fees(1)	$319,000	$272,293
Audit-Related Fees(2)	-	-
Tax Fees(3)	$24,292	$18,055
All Other Fees(4)	-	-
Total	**$343,292**	**$290,348**

(1) "Audit Fees" consist of fees for the audit of the Corporation's annual financial statements and the review of the Corporation's quarterly financial statements, as well as services that are normally provided in connection with statutory and regulatory filings or engagements.

(2) "Audit-Related Fees" consist of fees for assurance and related services that are reasonably related to the performance of the audit or the review of the Corporation's financial statements and are not reported under the heading of "Audit Fees" above.

(3) "Tax Fees" consist of fees for professional services rendered for tax compliance, tax advice and tax planning. During 2018 and 2017, such fees related to the preparation and filing of Birchcliff's corporate income tax returns and other tax-related work.

(4) "All Other Fees" consist of fees for products and services other than those described under the headings of "Audit Fees", "Audit-Related Fees" and "Tax Fees" above.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

The Corporation's 2006 income tax filings were reassessed by the CRA in 2011 (the "**Reassessment**"). The Reassessment was based on the CRA's position that the tax pools available to Veracel, prior to its amalgamation with Birchcliff, ceased to be available to Veracel after Birchcliff and Veracel amalgamated on May 31, 2005. The Veracel tax pools in dispute totalled $39.3 million. Birchcliff appealed the Reassessment to the Tax Court of Canada (the "**TCC**") and the trial of that appeal occurred in November 2013. On October 1, 2015, the TCC issued its decision (the "**TCC Decision**") and dismissed Birchcliff's appeal on the basis of the general anti-avoidance rule contained in the *Income Tax Act* (Canada). The TCC Decision was rendered by a judge based on the written record and not by the judge who conducted the trial. As a result of the TCC Decision, Birchcliff recorded a non-cash deferred income tax expense in the amount of $10.2 million in the fourth quarter of 2015. Birchcliff appealed the TCC Decision to the Federal Court of Appeal (the "**FCA**"), which appeal was heard in January 2017. On April 28, 2017, the FCA issued its decision and allowed the appeal and set aside the TCC Decision, based on the lack of jurisdiction by the judge who rendered the TCC Decision. In setting aside the TCC Decision, the FCA referred the matter back to the judge of the TCC who initially conducted the trial in 2013 to render a judgment. The judge of the TCC rendered a decision in November 2017 and dismissed Birchcliff's appeal. Birchcliff appealed that decision to the FCA, which appeal was heard on December 10, 2018, with the FCA reserving judgment.

There are no other material legal proceedings that the Corporation is or was a party to, or that any of its property is or was the subject of, during the most recently completed financial year or that the Corporation knows to be contemplated.

During the year ended December 31, 2018, there were: (i) no penalties or sanctions imposed against the Corporation by a court relating to securities legislation or by a securities regulatory authority; (ii) no other penalties or sanctions imposed by a court or regulatory body against the Corporation that would likely be considered important to a reasonable investor in making an investment decision; and (iii) no settlement agreements the Corporation entered into before a court relating to securities legislation or with a securities regulatory authority.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

There is no material interest, direct or indirect, of: (i) any director or executive officer of the Corporation; (ii) any person or company that beneficially owns, or controls or directs, directly or indirectly, more than 10% of the Common Shares; or (iii) any associate or affiliate of any of the persons or companies referred to in (i) or (ii), in any transaction within the three most recently completed financial years or during the current financial year that has materially affected or is reasonably expected to materially affect the Corporation.

TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for the Common Shares is Computershare Trust Company of Canada at its principal offices in Calgary, Alberta and Toronto, Ontario.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, the Corporation did not enter into any material contracts within the last financial year, or before the last financial year but which are still in effect.

INTERESTS OF EXPERTS

Names of Experts

The only persons or companies who are named as having prepared or certified a report, valuation, statement or opinion described or included in a filing, or referred to in a filing, made under NI 51-102 by the Corporation during, or relating to, the Corporation's most recently completed financial year, and whose profession or business gives authority to the report, valuation statement or opinion made by the person or company, are KPMG LLP, Deloitte and McDaniel.

Interests of Experts

KPMG LLP performed the audit in respect of the audited annual financial statements of the Corporation as at and for the years ended December 31, 2018 and December 31, 2017. KPMG LLP is considered independent of the Corporation within the meaning of the relevant rules and related interpretations prescribed by the relevant professional bodies in Canada and any applicable legislation or regulations.

The Corporation's independent qualified reserves evaluator, Deloitte, prepared the Deloitte Reserves Report, the Consolidated Reserves Report, the Prior Consolidated Reserves Report, the 2018 Resource Assessment and the 2017 Resource Assessment. As at the date hereof, the designated professionals (as defined in NI 51-102) of Deloitte, as a group, beneficially own, directly or indirectly, less than 1% of the securities of the Corporation.

The Corporation's independent qualified reserves evaluator, McDaniel, prepared the McDaniel Reserves Report. As at the date hereof, the designated professionals of McDaniel, as a group, beneficially own, directly or indirectly, less than 1% of the securities of the Corporation.

In addition, none of the aforementioned persons or companies, nor any partner, director, officer or employee of any of the aforementioned persons or companies, is or is expected to be elected, appointed or employed as a director, officer or employee of the Corporation.

ADDITIONAL INFORMATION

Additional information about the Corporation can be found on SEDAR at www.sedar.com and on the Corporation's website at www.birchcliffenergy.com. Additional information, including the remuneration and indebtedness of the directors and executive officers of the Corporation, the principal holders of Common Shares and the securities authorized for issuance under equity compensation plans, is contained in the information circular of the Corporation for the most recent annual meeting of the holders of Common Shares, which was held on May 10, 2018.

Additional financial information relating to the Corporation is provided in the Corporation's audited annual financial statements and related management's discussion and analysis for the year ended December 31, 2018.

APPENDIX A

DISCLOSURE OF CONTINGENT RESOURCES DATA AND PROSPECTIVE RESOURCES DATA

Birchcliff engaged Deloitte to prepare an independent evaluation of resources in respect of Birchcliff lands that have potential for the Montney/Doig Resource Play effective December 31, 2018, which is contained in a report dated March 13, 2019 (the "**2018 Resource Assessment**"). Deloitte also prepared a resource assessment effective December 31, 2017 (the "**2017 Resource Assessment**"). The 2018 Resource Assessment and the 2017 Resource Assessment were prepared in accordance with the standards contained in the COGE Handbook and NI 51-101 in effect at the relevant time.

Resource estimates contained herein at December 31, 2018 and 2017 are extracted from the relevant resource assessment and reflect only resources on Birchcliff's Montney/Doig lands. The resource assessments did not include any of Birchcliff's other properties. All anticipated results disclosed herein were prepared by Deloitte, who is an independent qualified reserves evaluator. Deloitte utilized probabilistic methods to generate high, best and low estimates of resource volumes.

Certain terms used herein are defined under the headings *"Glossary of Terms"* and *"Presentation of Oil and Gas Reserves and Resources"* in the Annual Information Form. Certain other terms used herein but not defined are defined in NI 51-101, CSA Staff Notice 51-324 or the COGE Handbook and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101, CSA Staff Notice 51-324 or the COGE Handbook, as the case may be.

All of Birchcliff's resources are located in the Province of Alberta. Unless otherwise indicated, all volumes of Birchcliff's resources presented herein are on an unrisked basis, meaning that they have not been adjusted for the chance of commerciality, and all volumes are presented on a gross basis, meaning Birchcliff's working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests of Birchcliff. Numbers in the tables presented herein may not total due to rounding.

The estimates of Birchcliff's resources provided herein are estimates only and there is no guarantee that the estimated resources will be recovered. Actual resources may be greater than or less than the estimates provided herein and variances could be material. With respect to Birchcliff's discovered resources (including contingent resources), there is uncertainty that it will be commercially viable to produce any portion of the resources. With respect to Birchcliff's undiscovered resources (including prospective resources), there is no certainty that any portion of the resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources. Estimates of future net revenue, whether calculated without discount or using a discount rate, do not represent fair market value. See *"Risk Factors and Uncertainties"* in this Appendix A and *"Risk Factors"* in the Annual Information Form to which this Appendix A is attached.

For further information regarding the presentation of Birchcliff's resource disclosure, see *"Presentation of Oil and Gas Reserves and Resources"* and *"Special Notes to Reader"* in the Annual Information Form.

Interest of Birchcliff in Resources in the Study Area

Birchcliff holds significant high working interest acreage in large contiguous blocks on the Montney/Doig Resource Play in the Peace River Arch area of Alberta. Birchcliff engaged Deloitte to evaluate the total PIIP and contingent and prospective resources on Birchcliff's lands for the Doig Phosphate ("**DoigP**"), Basal Doig ("**BD**") and Montney formations in the Montney/Doig Deep Basin area of northwest Alberta (the "**Study Area**"). In the Study Area, Birchcliff owns an interest in approximately 346.4 gross (338.4 net) sections of land which include Montney rights (inclusive of oil sections in the Gordondale area) and 322.1 gross (300.7 net) sections of land which include Doig rights. As compared to the 2017 Resource Assessment, these numbers are up approximately 6% for Montney rights (326.4 (319.3 net) sections as contained in the 2017 Resource Assessment) and 5% for Doig rights (307.1 (285.5 net) sections as contained in the 2017 Resource Assessment), primarily as a result of land acquisitions completed by the Corporation during 2018.

In the Study Area, resources have been assigned in areas ranging from Townships 69 to 80, Ranges 5 to 13W6. The Study Area is further bounded in a northwest-southeast direction by the Deep Basin edge. The geological section studied was divided into the DoigP, BD and Montney stratigraphic units. The Montney was further subdivided into seven intervals, from the top to the base: D5, D4, D3, D2, D1, TSE Valhalla and C.

Contingent resources have been attributed to Birchcliff's properties in the Pouce Coupe, Gordondale and Elmworth areas. Prospective resources have been attributed to Birchcliff's properties in the Pouce Coupe, Gordondale, Elmworth, Grande Prairie and Saddle Hills areas. Birchcliff's resources in the Pouce Coupe and Gordondale areas are proximal to Birchcliff's lands to which reserves have been attributed and to the Pouce Coupe Gas Plant, as well as to third party gathering and processing infrastructure. Birchcliff's resources in the Elmworth area are proximal to Birchcliff's lands to which reserves have been attributed and to third party gathering and processing infrastructure.

Birchcliff's average working interest in its gross best estimate contingent resources is 97% and its average working interest in its gross best estimate prospective resources is 97%.

Project Definition

Pursuant to NI 51-101, Birchcliff is required to describe the "projects" to which its resources have been attributed. "Project" is defined in the COGE Handbook as "a defined activity, or set of activities that provides the basis for the assessment and classification of resources". Deloitte segregated Birchcliff's Montney/Doig resources into development projects based on areal (property/area) and vertical (play interval) boundaries. The Study Area consisted of five areas with resources, namely: Pouce Coupe, Gordondale, Elmworth, Grande Prairie and Saddle Hills. The Montney/Doig formations are comprised of nine individually mapped stratigraphic units: the DoigP, the BD and the Montney D5, D4, D3, D2, D1, TSE and C stratigraphic units.

Stratigraphic units were combined for specific projects if Deloitte believed that a single well could produce from more than one unit at once and both zones have been designated as either prospective or contingent. If Birchcliff did not hold rights to all of the combined units across all of its land, they were classified as their own separate project for those particular sections. For details regarding Birchcliff's particular projects, see *"Contingent Resources"* and *"Prospective Resources"* in this Appendix A.

Summary of Discovered and Undiscovered Resources

The following table sets forth Birchcliff's gross best estimate contingent resources, prospective resources, total discovered and undiscovered PIIP and total PIIP at December 31, 2018 and December 31, 2017:

Summary of Discovered and Undiscovered Resources

	Volumes		
Resource Class	**December 31, 2018 *(Bcfe)***	**December 31, 2017 *(Bcfe)***	**Change from December 31, 2017**
Contingent Resources	13,146.9	12,358.4	6%
Total Discovered PIIP	41,499.7	39,027.6	6%
Prospective Resources	14,548.7	13,483.8	8%
Total Undiscovered PIIP	29,028.6	27,123.4	7%
Total PIIP	70,528.2	66,150.9	7%

Birchcliff's contingent and prospective resources, total discovered and undiscovered PIIP and total PIIP at December 31, 2018 all increased as compared to December 31, 2017, primarily as a result of the increase in mineral land rights held by Birchcliff as at December 31, 2018.

The following table sets forth Birchcliff's gross volumes for all resources, both discovered and undiscovered, at December 31, 2018:

Summary of Reserves and Resources

	Resource Class		Reserves and Resource Volumes (Bcfe)(1)		
		Raw/Sales	Low Estimate Case	Best Estimate Case	High Estimate Case
Discovered	Cumulative Production(2)	Sales	995.4	995.4	995.4
Discovered	Remaining Reserves(2)(3)	Sales	4,129.2	6,005.9	7,578.7
Discovered	Total Commercial Recoverable(2)	Sales	5,124.7	7,001.3	8,574.1
Discovered	Surface and Process Loss(4)	Raw	244.0	348.9	418.0
Discovered	Total Commercial	Raw	5,368.7	7,350.2	8,992.2
Discovered	**Contingent Resources(2)**	Sales	**9,115.6**	**13,146.9**	**20,269.6**
Discovered	Development Pending(2)	Sales	6,429.7	9,228.6	14,094.2
Discovered	Development On Hold(2)	Sales	2,330.3	3,389.0	4,978.0
Discovered	Development Unclarified(2)	Sales	243.0	373.1	959.9
Discovered	Development Not Viable(2)	Sales	112.5	156.3	237.5
Discovered	Surface and Process Loss	Raw	736.5	1,051.5	1,518.4
Discovered	Unrecoverable	Raw	17,802.1	19,951.1	20,878.0
Discovered	Total Sub-Commercial	Raw	27,654.3	34,149.5	42,666.0
Discovered	**TOTAL DISCOVERED PIIP**	Raw	**33,022.9**	**41,499.7**	**51,658.2**
Undiscovered	**Prospective Resources(2)**	Sales	**9,583.7**	**14,548.7**	**22,263.1**
Undiscovered	Prospect(2)(5)	Sales	9,583.7	14,548.7	22,263.1
Undiscovered	Surface and Process Loss	Raw	439.4	656.0	986.7
Undiscovered	Unrecoverable	Raw	11,472.3	13,823.9	14,885.5
Undiscovered	**TOTAL UNDISCOVERED PIIP**	Raw	**21,495.5**	**29,028.6**	**38,135.3**
TOTAL PIIP		Raw	**54,518.4**	**70,528.2**	**89,793.4**

(1) The volumes presented in the table above, other than cumulative production and reserves, have been presented on an unrisked basis, meaning that they have not been adjusted for the chance of commerciality.

(2) Sales gas, oil and NGLs volumes were combined at a ratio of 1 bbl: 6 Mcfe.

(3) Includes reserves assigned to both vertical and horizontal Montney/Doig wells in the Consolidated Reserves Report. Birchcliff has ongoing projects to drill horizontal wells targeting the Montney. This has resulted in some of the areas in the Study Area already having been assigned undeveloped reserves by Birchcliff's independent qualified reserves evaluators. The reserves assignments as of the effective date of the 2018 Resource Assessment have been subtracted from the resource estimates. Proved, probable and possible reserves as contained in the Consolidated Reserves Report are included in the above table for completeness; however, reserves were not the focus of the 2018 Resource Assessment. The low estimate case includes the estimate of proved reserves contained in the Consolidated Reserves Report, the best estimate case includes the estimate of proved plus probable reserves contained in the Consolidated Reserves Report and the high estimate case includes the estimate of proved plus probable plus possible reserves contained in the Consolidated Reserves Report. Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.

(4) Includes surface and process loss attributed to cumulative production and remaining reserves volumes.

(5) All of Birchcliff's prospective resources were sub-classified into the project maturity sub-class of "prospect". See *"Prospective Resources – Project Maturity Sub-classes for Prospective Resources"* in this Appendix A.

Contingent Resources

Summary of Risked Contingent Resources

The following table sets forth Birchcliff's best estimate (2C) risked contingent resources by product type at December 31, 2018, estimated using the Deloitte Price Forecast:

Summary of Risked Contingent Resources – 2C
at December 31, 2018
(Forecast Prices and Costs)

Resources Project Maturity Sub-class(1)	Shale Gas(2)		NGLs		Light Crude and Medium Crude Oil		Total	
	Gross(3) (Bcf)	*Net(4) (Bcf)*	*Gross(3) (MMbbls)*	*Net(4) (MMbbls)*	*Gross(3) (MMbbls)*	*Net(4) (MMbbls)*	*Gross(3) (Bcfe)*	*Net(4) (Bcfe)*
Development Pending	6,968.2	5,600.6	173.6	96.5	4.6	3.6	8,037.1	6,201.2
Development On Hold	1,770.5	N/A	48.4	N/A	-	N/A	2,060.6	N/A
Development Unclarified	106.3	N/A	7.0	N/A	0.2	N/A	149.2	N/A
Development Not Viable	20.7	N/A	1.8	N/A	-	N/A	31.3	N/A

(1) For a description of the project maturity sub-classes applicable to the Corporation's contingent resources, see *"Contingent Resources – Project Maturity Sub-classes for Contingent Resources"* in this Appendix A.

(2) The associated solution gas from the assigned oil resource locations has been included in the shale gas product type.

(3) Gross risked contingent resources are technical volumes.

(4) Net volumes presented in the table above are economic volumes using a 50-year cut-off date of December 31, 2068. Economics were not evaluated for Birchcliff's development on hold, development unclarified or development not viable contingent resources. Accordingly, no information is available for royalties and a net number cannot be determined.

At December 31, 2018, Birchcliff had gross best estimate contingent resources of 13,146.9 Bcfe (unrisked before adjusting for the chance of commerciality) and gross best estimate contingent resources of 10,278.2 Bcfe (risked after adjusting for the chance of commerciality).

Summary of the Risked Net Present Value of Development Pending Contingent Resources

The following table sets forth the net present value of future net revenue of Birchcliff's best estimate risked contingent resources in the development pending project maturity sub-class at December 31, 2018, estimated using the Deloitte Price Forecast:

Summary of Risked Net Present Value of Future Net Revenue of Development Pending Contingent Resources
at December 31, 2018
(Forecast Prices and Costs)

	Risked Net Present Value of Future Net Revenue Before Income Taxes Discounted at (%/year)[(1)(2)]				
Resources Project Maturity Sub-class	**0** ***(MM\$)***	**5** ***(MM\$)***	**10** ***(MM\$)***	**15** ***(MM\$)***	**20** ***(MM\$)***
Contingent (2C) Development Pending	24,801.8	5,749.8	1,607.8	505.4	164.2

(1) The net present value of future net revenue attributable to the Corporation's development pending contingent resources is based on the Deloitte Price Forecast and is determined before provision for interest, debt servicing and general and administrative expense and after the deduction of royalties, operating costs, development costs and abandonment and reclamation costs.

(2) Amounts presented in the table above are economic volumes using a 50-year cut-off date of December 31, 2068.

An estimate of risked net present value of future net revenue of contingent resources is preliminary in nature and is provided to assist the reader in reaching an opinion on the merit and likelihood of the Corporation proceeding with the required investment. It includes contingent resources that are considered too uncertain with respect to the chance of development to be classified as reserves. There is uncertainty that the estimate of risked net present value of future net revenue will be realized.

The Deloitte Price Forecast is summarized in the Annual Information Form under the heading *"Statement of Reserves Data and Other Oil and Gas Information – Pricing Assumptions"*.

Chance of Commerciality of Contingent Resources

As all contingent resources are considered to be discovered, the chance of commerciality is equal to the chance of development for contingent resources. "Chance of development" is the estimated probability that, once discovered, a known accumulation will be commercially developed. Deloitte referred to the five requirements outlined in the COGE Handbook for commerciality when estimating the chance of development for Birchcliff's contingent resource projects. These requirements include: (i) the project is economically viable; (ii) there is a market for the forecast sales quantities of production required to justify development; (iii) the necessary production, transportation facilities and access to infrastructure are available or can be made available; (iv) the regulatory, environmental, societal and political conditions will allow for the actual implementation of the recovery project being evaluated; and (v) all required internal and external approvals are forthcoming. Evidence of this may include items such as signed contracts, budget approvals, and approvals for expenditures.

Evaluation of each of these items are qualitative in nature. Deloitte stated that it had no reason to believe that requirements (ii), (iv) or (v) are significantly better or worse when comparing development pending projects against each other. The most tangible distinction between development pending projects was requirement (iii) (the necessary production, transportation facilities and access to infrastructure are available or can be made available) and therefore served as the basis for selecting the chance of commerciality for these projects. The guidance in the COGE Handbook recommends a high chance of success should be at minimum 80%. Out of the Pouce Coupe, Gordondale and Elmworth properties, infrastructure in the Pouce Coupe and Gordondale properties is the most developed. Plant expansions and sizeable investment committed to pipeline infrastructure are supported in the Deloitte Reserves Report. For this reason, all development pending Pouce Coupe projects were assigned the highest chance of commerciality of 90% by Deloitte.

The Gordondale area has infrastructure and maintenance costs forecast in the McDaniel Reserves Report. Deloitte has assigned a 90% chance of commerciality for the development pending D1/TSE gas and D2 oil, gas and transition projects based on the existing infrastructure in the area. For the development pending BD/D5/DoigP, BD/DoigP only and D4 projects, Deloitte has assigned an 80% chance of commerciality to such projects due to the lack of development on these zones in the area to date. In addition, to account for low pressure lands within the DoigP, BD and D5 Montney zones on the Gordondale property, Deloitte has risked the associated projects by assigning lower recoverable volumes on a per location basis.

Projects in the Elmworth area have little to no infrastructure investment booked in the Deloitte Reserves Report. All development pending Elmworth projects were assigned an 80% chance of commerciality as these projects are forecast to be processed through a natural gas processing plant assumed by Deloitte in its assessment (the "**Assumed Elmworth Plant**") affecting certainty in operating costs and the economics of the project.

The chance of development is expected to decrease for other maturity sub-classes based on requirements (i) and (iii). The uncertainty associated with these requirements typically increases in the development on hold, development unclarified and development not viable sub-classes. Deloitte modelled this by estimating the chance of commerciality values to be 60% for development on hold, 40% for development unclarified and 20% for development not viable projects. These projects have lower chances of commerciality as a result of the priority of development being given to other contingent projects, due to distance to infrastructure and less desirable economics. The estimated contingent resources and associated net present values are simply multiplied by the chance of commerciality in the economic software to result in risked volumes and net present values.

Project Maturity Sub-classes for Contingent Resources

Contingent resources can be sub-classified based on their project maturity sub-class. The project maturity sub-classes for contingent resources are "development pending", "development on hold", "development unclarified" or "development not viable", all as defined in the COGE Handbook. "Development pending" is when resolution of the final conditions for development is being actively pursued (high chance of development). "Development on hold" is when there is a reasonable chance of development, but there are major non-technical contingencies to be resolved that are usually beyond the control of the operator. "Development unclarified" is when the evaluation is incomplete and there is ongoing activity to resolve any risks or uncertainties. "Development not viable" is when no further data acquisition or evaluation is currently planned and hence there is a low chance of development.

Approximately 70% of Birchcliff's gross unrisked best estimate case contingent resources were sub-classified as development pending, 26% were sub-classified as development on hold, 3% were sub-classified as development unclarified and less than 1% were sub-classified as development not viable. Although Birchcliff's development unclarified and development not viable projects do not represent a material amount of Birchcliff's estimated contingent resources, the Corporation has chosen to disclose the estimated volumes of such resources for completeness.

Birchcliff's contingent resources were sub-classified by Deloitte as development pending, development on hold, development not viable or development unclarified as described below.

Development Pending

Each contingent resource project was sub-classified as development pending if the contingent resource project is currently economic and satisfies the COGE Handbook requirements of commerciality in that:

(i) there is an expected market for the sale of forecast production volumes from the project;

(ii) the necessary production and transportation facilities are expected to be available in the relevant time frame, as a result of Birchcliff's long range forward planning;

(iii) there is no reasonable expectation that legal, contractual, environmental, governmental and other social and economic concerns will preclude the development of the project since project development is in the same area and follows the same business model that Birchcliff has been implementing over the last 11 years with respect to the development of its Montney/Doig Resource Play;

(iv) there is a reasonable expectation that internal and external approvals will be forthcoming in a timely manner since project development is in the same area and follows the same business model that Birchcliff has been implementing over the last 11 years with respect to the development of its Montney/Doig Resource Play; and

(v) Birchcliff intends to move forward with the development of the project within a reasonable time frame as it moves towards completion of the development of its reserves.

Development On Hold

Each contingent resource project was sub-classified as development on hold if it could be economic at some point in the future. In addition, some contingent resource projects satisfied the conditions for development pending; however, if the Corporation indicated that it currently had no intention of developing these resources within a reasonable timeframe, the project was sub-classified as development on hold. This applied to one of the Corporation's projects in Pouce Coupe (the C development on hold project), one of the Corporation's projects in Gordondale (the C on hold project) and two of the Corporation's projects in the Elmworth North area (the BD/D5/DoigP on hold and the BD/DoigP only on hold projects). See *"Contingent Resources – Birchcliff's Contingent Resource Projects".*

Development Unclarified

Contingent resource projects with limited information and uncertain economics were sub-classified as development unclarified. These projects will require further examination in the future to move into a different project maturity sub-class.

Development Not Viable

Contingent resource projects were sub-classified as development not viable when their contingent volumes had a low chance of development due to no further plans for data acquisition or evaluation. These projects are unlikely to ever be economic. The reclassification from development not viable to development on hold can only occur if prices increase beyond the current Deloitte Price Forecast assuming the same project economics.

Economic Status Criteria of Contingent Resource Project Maturity Sub-classes

For purposes of addressing the project economic criterion of each of the project maturity sub-classes, Deloitte applied the following criteria:

(i) each resource project was considered currently economic if the project had a positive NPV discounted at a rate of 10% (before income taxes) using the Deloitte Price Forecast with current capital and operating expense assumptions;

(ii) Deloitte considered that a resource project could be economic at some point in the future if the project had a positive undiscounted NPV (before income taxes) using the Deloitte Price Forecast that was increased by 20%; and

(iii) Deloitte considered that a resource project was unlikely to ever be economic if the project did not have a positive undiscounted NPV (before income taxes) using the Deloitte Price Forecast that was increased by 20%.

Economic Classification of Contingent Resources

Contingent resource estimates should have sufficient economic analysis to sub-classify the resource as either economic or sub-economic under economic conditions that are the same as those used for reporting reserves. The appropriate level of economic evaluation will depend on the project status and maturity. Economic contingent resources are those contingent resources that are currently economically recoverable based on specific forecasts of production, capital and operating costs, commodity prices and inflation. Sub-economic contingent resources are those contingent resources that are not currently economically recoverable based on specific forecasts of production, capital and operating costs, commodity prices and inflation. Each contingent resource project was sub-classified by Deloitte as economic if the project had a positive NPV discounted at a rate of 10% (before income taxes) using the Deloitte Price Forecast with current capital and operating expense assumptions. Each contingent resource project that did not meet this economic hurdle was sub-classified as sub-economic. Where evaluations are incomplete such that it is premature to identify the economic viability of a project, the economic status was sub-classified as undetermined.

All of Birchcliff's development pending projects were sub-classified as economic and Birchcliff's development not viable and development on hold projects were sub-classified as sub-economic. Development unclarified projects were sub-classified as economic status undetermined.

Approximately 70% of Birchcliff's unrisked best estimate contingent resources were sub-classified as economic contingent resources, 27% were sub-classified as sub-economic contingent resources and 3% were sub-classified as economic status undetermined.

Birchcliff's Contingent Resource Projects

The following table sets forth for each of Birchcliff's contingent resource projects, the project maturity sub-class, the chance of commerciality, the economic status, the estimated total cost to achieve commercial production, the timeline of each project and the estimated date of first commercial production and the number of resource locations:

Contingent Resource Projects

Project		Project Maturity Sub-class	Chance of Commer-ciality[(1)]	Economic Status	Estimated Total Cost to Achieve Commercial Production (MM$)[(2)]	Timeline of Project and Estimated Date of First Commercial Production[(2)]	Resource Locations[(2)(5)]
Pouce Coupe Area							
Pouce Coupe	BD/D5/DoigP	Development Pending	90%	Economic		2029	173
Pouce Coupe	BD/DoigP Only[(6)]	Development Not Viable	20%	Sub-Economic		N/A	N/A
Pouce Coupe	D5 Only[(6)]	Development Pending	90%	Economic		2029	36
Pouce Coupe	D4	Development Pending	90%	Economic		2029	268
Pouce Coupe	D3	Development Unclarified	40%	Undetermined		N/A	N/A
Pouce Coupe	D2	Development Pending	90%	Economic		2030	201
Pouce Coupe	D1/TSE	Development Pending	90%	Economic		2035	92
Pouce Coupe	C Dev Pending	Development Pending	90%	Economic		2043	470
Pouce Coupe	C Dev On Hold	Development On Hold	60%	Sub-Economic		N/A	N/A
Pouce Coupe	Plant & Infrastructure Capital[(7)]	Development Pending	90%	Economic		2029	N/A
				Total	**0.0**[(3)]	**Total**	**1,240**
Gordondale Area							
Gordondale	BD/D5/DoigP	Development Pending	80%	Economic		2029	118
Gordondale	BD/DoigP Only[(6)]	Development Pending	80%	Economic		2029	3
Gordondale	BD/DoigP Only On Hold[(6)]	Development On Hold	60%	Sub-Economic		N/A	N/A
Gordondale	D5 Only[(6)]	Development Not Viable	20%	Sub-Economic		N/A	N/A
Gordondale	D4	Development Pending	80%	Economic	5.7[(3)]	2033	109
Gordondale	D2 Oil[(8)]	Development Pending	90%	Economic		2029	26
Gordondale	D2 Transition	Development Pending	90%	Economic		2029	31
Gordondale	D2 Gas	Development Pending	90%	Economic		2034	47
Gordondale	D1/TSE Oil[(8)]	Development Unclarified	40%	Undetermined		N/A	N/A
Gordondale	D1/TSE Gas	Development Pending	90%	Economic		2029	14
Gordondale	C	Development On Hold	60%	Sub-Economic		N/A	N/A
Gordondale	Plant & Infrastructure Capital[(7)]	Development Pending	90%	Economic		2029	N/A
				Total	**5.7**[(3)]	**Total**	**348**
Elmworth Area							
Elmworth South	D5	Development On Hold	60%	Sub-Economic		N/A	N/A
Elmworth South	D4	Development Pending	80%	Economic		2033	52
Elmworth North	BD/D5/DoigP Pending	Development Pending	80%	Economic	5.8[(4)]	2027	89
Elmworth North	BD/D5/DoigP On Hold	Development On Hold	60%	Sub-Economic		N/A	N/A
Elmworth North	BD/DoigP Only Pending[(6)]	Development Pending	80%	Economic	6.1[(4)]	2029	83
Elmworth North	BD/DoigP Only On Hold[(6)]	Development On Hold	60%	Sub-Economic		N/A	N/A
Elmworth North	D5 Only[(6)]	Development On Hold	60%	Sub-Economic		N/A	N/A
Elmworth North	D4	Development Pending	80%	Economic		2032	191
Elmworth North	D2	Development On Hold	60%	Sub-Economic		N/A	N/A
Elmworth North	D1/TSE	Development On Hold	60%	Sub-Economic		N/A	N/A
Elmworth	Plant & Infrastructure Capital[(7)]	Development Pending	80%	Economic	73.5[(4)]	2026	N/A
				Total	**84.4**[(4)]	**Total**	**415**
				GRAND TOTAL	**91.1**	**GRAND TOTAL**	**2,003**

(1) See *"Contingent Resources – Chance of Commerciality of Contingent Resources"* in this Appendix A for information regarding the process employed by Deloitte to risk Birchcliff's contingent resources.

(2) With respect to the estimated total cost to achieve commercial production, the costs set forth in the table above represent Birchcliff's working interest portion (inflated) of the capital required to achieve initial commercial production for the project area, as discussed in further detail herein. With respect to the timelines of projects and the estimated date of first commercial production, timelines are based on the development plan that was used by Deloitte in the 2018 Resource Assessment and reflect the expected dates that further drilling of those resource projects will first occur under such plan. Development plans were only created

for those contingent resources sub-classified as development pending. As no development plans were created for contingent resources in the development on hold, development unclarified or development not viable project maturity sub-classes, there is insufficient information to determine the estimated total cost to achieve commercial production, the timeline of the project or the number of resource locations.

(3) With respect to Birchcliff's development pending projects in the Pouce Coupe area and the Gordondale area (other than the D4 project), there are no costs to achieve commercial production, as the necessary infrastructure is expected to be in place as a result of the development of the Corporation's existing commercial projects. With respect to the D4 project in the Gordondale area, the estimated costs are approximately $5.7 million which represents the risked cost of the first well in that interval that would be necessary for Birchcliff to achieve commercial production in that interval.

(4) The costs to achieve commercial production represent the required initial facility capital for the Elmworth area and represent all projects in the project area. With respect to Birchcliff's development pending projects in the Elmworth area (other than the BD/D5/DoigP and BD/DoigP Only projects and Facility & Infrastructure capital), there are no costs to achieve commercial production, as the necessary infrastructure is expected to be in place as a result of the development of the Corporation's existing commercial projects and the Assumed Elmworth Plant and infrastructure. With respect to the BD/D5/DoigP project and the BD/DoigP Only project in the Elmworth North area, the estimated cost is approximately $5.8 million and $6.1 million, respectively, which represent the risked cost of the first well in that interval that would be necessary for Birchcliff to achieve commercial production in that interval.

(5) Resource locations represent the number of wells forecast to be drilled under the development plan for development pending projects.

(6) Birchcliff does not hold rights to all of the combined stratigraphic units within this area so this project was created.

(7) Plant and infrastructure projects consist of facility developments and the associated costs required to develop resources according to the modeled development plan. Such projects are further described under the heading *"Contingent Resources – Development Plans for Development Pending Projects"* and include new major pipelines, new plant capacities, increases of plant capacities and sustaining pipeline and compression projects.

(8) Sections include oil volumes, solution gas, free gas and sorbed gas.

The total cost to achieve commercial production for all projects disclosed in the table above is estimated to be $91.1 million. The total cost to achieve commercial production only includes the capital required to achieve initial commercial production for the project area (for example, required facility and pipeline capital) and does not represent the total capital required to develop the entire project. The total capital required to fully develop the projects set forth in the table above (including total costs to achieve commercial production and total sustaining capital) is estimated to be approximately $13,465.8 million (undiscounted) as follows: (i) Pouce Coupe Area: $8,189.0 million; (ii) Gordondale Area: $2,008.4 million; and (iii) Elmworth Area: $3,268.4 million. Total capital amounts represent Birchcliff's working interest portion (inflated).

The recovery technology for each contingent resource project described above is multi-fracture horizontal wells, which is considered an established technology under the COGE Handbook. All of the contingent resource projects described above are based on pre-development studies.

Development Plans for Development Pending Projects

Overview

Development plans were created for those projects sub-classified as development pending. Such plans were determined by Deloitte and are consistent with the guidance and input provided by Birchcliff. Deloitte has modelled what is considered a reasonable development plan for development pending contingent resources. In order to create a development schedule for each project, Deloitte utilized an internally built development planning tool. The tool automated the field development plan based on various configurable inputs and constraints while maximizing NPV discounted at a rate of 10% (before income taxes). In addition, unique constraints were applied to each of the facilities assumed by Deloitte in its development plans which were modelled into the development planning tool and the optimal drilling schedule for each plant was calculated.

The uncertainty relating to the development of each of the development pending projects primarily relates to the timing and corporate sanctioning for the development of these resources. Deloitte has forecast development to begin in 2026. There can be no certainty that any of the projects described herein will be developed on the timelines discussed herein. Development of the projects is dependent on a number of contingencies as further described herein, as well as numerous risk factors and uncertainties.

Projects in the Pouce Coupe Area

All of Birchcliff's contingent development pending projects in the Pouce Coupe area (excluding the plant and infrastructure capital project) were assumed by Deloitte to produce to the Pouce Coupe Gas Plant. In determining the development plans for such projects, Deloitte relied on the following assumptions relating to the Pouce Coupe Gas Plant:

- The maximum plant capacity will be increased to 660 MMcf/d in October 2022.
- The maximum number of resource locations (wells) drilled per year cannot exceed 100 for the life of the resource development.
- The maximum resource locations for each project cannot be exceeded.

For these projects, the proposed resource development plans contemplate that the drilling of the 1,240 resource locations identified in the table above will take place over 23 years from 2029 to 2051. Under the proposed development plans for these projects, all resource locations will be drilled by 2051. The plant and infrastructure capital is for sustaining existing pipelines (forecast to be incurred from 2029 to 2051) and additional compression support (forecast to be incurred from 2052 to 2056).

Projects in the Elmworth Area

All of Birchcliff's contingent development pending projects in the Elmworth North and South areas (excluding the plant and infrastructure capital project) were assumed by Deloitte to produce to the Assumed Elmworth Plant. In determining the development plans for such projects, Deloitte relied on the following assumptions for the Assumed Elmworth Plant:

- The maximum plant capacity will be 40 MMcf/d in 2027, which increases to 80 MMcf/d in 2029, 120 MMcf/d in 2030 and 180 MMcf/d in 2031.
- The maximum number of resource locations drilled per year cannot exceed 35 for the life of the resource development.
- The maximum resource locations for each project cannot be exceeded.

For these projects, the proposed resource development plans contemplate that the drilling of the 415 resource locations identified in the table above will take place over 22 years from 2027 until 2048. The plant and infrastructure capital is for the Assumed Elmworth Plant, a sales pipeline and a trunk pipeline (forecast to be incurred in 2027), gas plant expansions (forecast to be incurred in 2029 to 2031), additional pipeline infrastructure (forecast to be incurred from 2032 to 2048) and additional compression support (forecast to be incurred from 2049 to 2053).

Projects in the Gordondale Area

All of Birchcliff's contingent development pending projects in the Gordondale area (excluding the plant and infrastructure capital project) were assumed by Deloitte to produce to either the Gordondale Gas Plant or an assumed shallow-cut expansion to the existing Gordondale Gas Plant (the "**Assumed Shallow-Cut Plant**"). The BD/D5/DoigP and BD/DoigP only projects were forecast to be processed through the Assumed Shallow-Cut Plant and the remaining development pending projects were forecast to be processed through the Gordondale Gas Plant. In determining the development plans for such projects, Deloitte relied on the following assumptions for the Gordondale Gas Plant and the Assumed Shallow-Cut Plant:

- The maximum plant capacity for the Gordondale Gas Plant will remain at 120 MMcf/d.
- The capacity of the Assumed Shallow-Cut Plant will be 30 MMcf/d.
- The maximum number of resource locations drilled per year cannot exceed 55 for the life of the resource development.
- The maximum resource locations for each project cannot be exceeded.

For these projects, the proposed resource development plans contemplate that the drilling of the 348 resource locations identified in the table above will take place over 31 years from 2029 until 2059. The plant and infrastructure capital is for pipeline infrastructure (forecast to be incurred from 2029 to 2045) and additional compression support (forecast to be incurred from 2046 to 2050).

Contingencies

Contingent resources are not currently considered to be commercially recoverable due to one or more contingencies. A contingency is a condition that must be satisfied for a portion of contingent resources to be classified as reserves that is specific to the project being evaluated and expected to be resolved within a reasonable timeframe. Contingencies may include factors such as economic, legal environmental, political and regulatory matters or a lack of markets.

Development Pending Project Maturity Sub-classes

The development of each of Birchcliff's development pending projects is contingent upon:

- Birchcliff obtaining the necessary internal approvals for the expenditure of capital on the development project; and
- Birchcliff initiating field development in an appropriate timeframe.

These contingencies are expected to be resolved as a result of Birchcliff developing and implementing plans over time in an orderly fashion.

Development on Hold and Development Not Viable Project Maturity Sub-classes

In addition to the contingencies described above for Birchcliff's development pending projects, the development of each of Birchcliff's development on hold projects is also contingent upon the ability of the project to compete with projects which have a greater chance of commerciality for finite development capital and resources and the strategic considerations relating to the scale and efficiencies of these projects. These contingencies are expected to be resolved over time through Birchcliff's orderly clarification of sanctioned corporate plans through its five-year plan and annual budget processes.

Development Unclarified Project Maturity Sub-classes

In addition to the contingencies described above for Birchcliff's development pending projects, the development of each of Birchcliff's development unclarified projects is also contingent upon clarifying uncertainties in the economic evaluation and production forecasts consistent with an early stage of development for the project. These contingencies are expected to be resolved by the continued economic evaluation of future production and development.

Projects Involving Expanded or New Facilities/Infrastructure

In addition to the contingencies described above for Birchcliff's development pending projects, all of Birchcliff's contingent resource projects are contingent upon the development of the facilities/infrastructure described under the heading *"Contingent Resources – Development Plans for Development Pending Projects"*. These additional contingencies are expected to be resolved by the sanctioned approval and construction of the described facilities.

Projects Producing Sour Gas

In addition to the contingencies described above for Birchcliff's development pending projects, the development of each of Birchcliff's contingent resource projects expected to deliver volumes of sour gas (H_2S) have the following additional contingencies:

- Birchcliff obtaining the necessary regulatory approvals;
- the design, construction and maintenance by Birchcliff of sour gas disposal wells and facilities; and

- Birchcliff maintaining social licence for the development of the project with surface landholders, First Nations and other stakeholders.

These contingencies apply to all projects in the Elmworth North and South areas. These additional contingencies can be resolved by Birchcliff implementing best practices in these operations and by Birchcliff effectively engaging with regulatory authorities, surface landholders, First Nations and other stakeholders.

Full Field Development

The complete full field development of each of Birchcliff's contingent resource projects is contingent upon:

- Birchcliff continuing proactive effective long range planning and design (surface and sub-surface) of all future development wells involved in the project; and

- Birchcliff obtaining the necessary regulatory approvals, particularly related to downspacing in the Montney.

These additional contingencies are expected to be resolved by continuing to implement development consistent with full field development plans and effectively engaging with regulatory authorities.

Prospective Resources

Summary of Risked Prospective Resources

The following table sets forth Birchcliff's best estimate risked prospective resources by product type at December 31, 2018:

Summary of Risked Prospective Resources – Best Estimate
at December 31, 2018

	Shale Gas		NGLs		Light Crude Oil and Medium Crude Oil		Total	
Resources	***Gross (Bcf)***	***Net[2] (Bcf)***	***Gross (MMbbls)***	***Net[2] (MMbbls)***	***Gross (MMbbls)***	***Net[2] (MMbbls)***	***Gross (Bcfe)***	***Net[2] (Bcfe)***
Prospective (Best Estimate)[1][2]	4,645.3	N/A	79.3	N/A	0.1	N/A	5,121.4	N/A

(1) All of Birchcliff's prospective resources are sub-classified into the project maturity sub-class of "prospect". For a description of the project maturity sub-classes applicable to prospective resources, see *"Prospective Resources – Project Maturity Sub-classes for Prospective Resources"* in this Appendix A. The numbers in the table above are technical volumes.

(2) Numbers are not applicable because economics were not evaluated for Birchcliff's prospective resources. As economics were not evaluated, no information is available for royalties and a net number cannot be determined.

At December 31, 2018, Birchcliff had gross best estimate prospective resources of 14,548.7 Bcfe (unrisked before adjusting for the chance of commerciality) and 5,121.4 Bcfe (risked after adjusting for the chance of commerciality).

Chance of Commerciality of Prospective Resources

The chance of commerciality for prospective resources is equal to the product of the chance of discovery and the chance of development. "Chance of discovery" is the estimated probability that exploration activities will confirm the existence of a significant accumulation of potentially recoverable petroleum. "Chance of development" is the estimated probability that, once discovered, a known accumulation will be commercially developed. The chance of discovery associated with Birchcliff's prospective resource volumes has been estimated by Deloitte to be 90% for all projects with a chance of development of either 40% or 30%, resulting in an overall chance of commerciality of 36% or 27%.

The chance of discovery was estimated to be 90% due to the relatively high geological certainty of encountering the specific zone in each project and area. Birchcliff and nearby industry competitors have and continue to refine the geological model within and outside of the Study Area. Additionally, Deloitte's four mile radius boundary in conjunction with geological mapping and the exploration success of Birchcliff and nearby industry competitors with similar resources and under varying conditions indicates that the resource play is well understood from an exploratory viewpoint.

The chance of development was estimated to be 40% for projects in high pressure zones due to the priority given to the further development of the existing plays and the contingent projects, the greater distance to existing reserves and the greater distance to existing infrastructure. This also takes into account Birchcliff's high working interest and operatorship of its assets as the Corporation is not subject to the priorities of working interest partners for such assets. For prospective projects outside of the low pressure boundary, the chance of development was estimated to be 30%. The factor was decreased as individual well deliverability will most likely be an issue in the low pressure zones during the development of these projects.

Project Maturity Sub-classes for Prospective Resources

Prospective resources can be sub-classified based on their project maturity sub-class. The project maturity sub-classes for prospective resources are "prospect", "lead" and "play", all as defined in the COGE Handbook. A "prospect" is defined as a potential accumulation within a play that is sufficiently well defined to represent a viable drilling target. A "lead" is defined as a potential accumulation within a play that requires more data acquisition and/or evaluation in order to be sub-classified as a prospect. A "play" is defined as a family of geologically similar fields, discoveries, prospects and leads. 100% of Birchcliff's prospective resources were sub-classified as prospects.

Birchcliff's Prospective Resource Projects

The following is a description of each of Birchcliff's prospective resource projects:

Project		Chance of Discovery	Chance of Development	Chance of Commerciality
Pouce Coupe	D4	90%	40%	36%
Pouce Coupe	D3	90%	40%	36%
Pouce Coupe	D2	90%	40%	36%
Gordondale	BD/D5/DoigP[1]	90%	30%	27%
Gordondale	BD/DoigP Only[1][2]	90%	30%	27%
Gordondale	D5 Only[1][2]	90%	30%	27%
Gordondale	D4[1]	90%	30%	27%
Gordondale	D3[1]	90%	30%	27%
Gordondale	D2 Oil	90%	40%	36%
Gordondale	C	90%	40%	36%
Elmworth	DoigP	90%	40%	36%
Elmworth	BD	90%	40%	36%
Elmworth	D5	90%	40%	36%
Elmworth	D4	90%	40%	36%
Elmworth	D3	90%	40%	36%
Elmworth	D2	90%	40%	36%
Elmworth	D1/TSE	90%	40%	36%
Elmworth	C	90%	40%	36%
Elmworth North	BD/D5/DoigP	90%	40%	36%
Elmworth North	BD/DoigP Only[2]	90%	40%	36%
Elmworth North	D5 Only[2]	90%	40%	36%
Elmworth North	D4	90%	40%	36%
Elmworth North	D3	90%	40%	36%
Elmworth North	D2	90%	40%	36%
Elmworth North	D1 Only	90%	40%	36%
Elmworth North	TSE Only	90%	40%	36%
Elmworth North	C	90%	40%	36%
Elmworth South	BD/DoigP Only[2]	90%	40%	36%
Elmworth South	D5	90%	40%	36%
Elmworth South	D4	90%	40%	36%
Elmworth South	D3	90%	40%	36%
Elmworth South	D2	90%	40%	36%
Elmworth South	D1/TSE	90%	40%	36%
Elmworth South	C	90%	40%	36%
Saddle Hills	DoigP[1]	90%	30%	27%

Project		Chance of Discovery	Chance of Development	Chance of Commerciality
Saddle Hills	DoigP(1)	90%	30%	27%
Saddle Hills	BD(1)	90%	30%	27%
Saddle Hills	D5(1)	90%	30%	27%
Saddle Hills	D4(1)	90%	30%	27%
Saddle Hills	D3(1)	90%	30%	27%
Saddle Hills	D2(1)	90%	30%	27%
Saddle Hills	D1(1)	90%	30%	27%
Saddle Hills	TSE(1)	90%	30%	27%
Saddle Hills	C(1)	90%	30%	27%
Grande Prairie	DoigP(1)	90%	30%	27%
Grande Prairie	BD(1)	90%	30%	27%
Grande Prairie	D5(1)	90%	30%	27%
Grande Prairie	D4(1)	90%	30%	27%
Grande Prairie	D3(1)	90%	30%	27%
Grande Prairie	D2(1)	90%	30%	27%
Grande Prairie	D1(1)	90%	30%	27%
Grande Prairie	TSE(1)	90%	30%	27%
Grande Prairie	C(1)	90%	30%	27%

(1) These projects have a lower chance of development assigned as they fall within the low pressure boundary.

(2) Birchcliff does not hold rights to all of the combined stratigraphic units within this area so this project was created.

The recovery technology for each project described above is multi-fracture horizontal wells which is considered an established technology under the COGE Handbook. All of the projects described above are based on intermediate stage studies.

Risk Factors and Uncertainties

General

There are numerous uncertainties inherent in estimating quantities of resources and the future net revenue attributed to the best estimate of the Corporation's development pending contingent resources. The resource and associated future net revenue information for the best estimate of the development pending contingent resources set forth herein are estimates only.

In general, estimates of resources and the future net revenue therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate resource recovery, the timing and amount of capital expenditures, marketability of oil, NGLs and natural gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially from actual results. For these reasons, estimates of the resources attributable to any particular group of properties, the classification of such resources based on risk of recovery and estimates of future net revenue associated with resources prepared by different engineers, or by the same engineer at different times, may vary. Birchcliff's actual production, revenues, taxes and development and operating expenditures with respect to its resources will vary from estimates thereof and such variations could be material.

It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to the best estimate of Birchcliff's development pending contingent resources represent the fair market value of those resources. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. The estimates of Birchcliff's resources provided herein are estimates only and there is no guarantee that the estimated resources will be recovered. Actual resources may be greater than or less than the estimates provided herein and variances could be material. With respect to the discovered resources (including contingent resources), there is uncertainty that it will be commercially viable to produce any portion of the resources. With respect to the undiscovered resources (including prospective resources), there is no certainty that any portion of the resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources.

For further information regarding the risks and uncertainties relating to Birchcliff and its properties to which no reserves have been attributed, see *"Statement of Reserves Data and Other Oil and Gas Information – Other Oil and Gas Information – Properties with No Attributed Reserves"* and *"Risk Factors"* in the Annual Information Form.

Risk Factors and Uncertainties

There are numerous factors and uncertainties that affect the anticipated development of the Corporation's resources.

The chances of development for the estimated resources are subject to a number of factors, including overall project economics, the employed recovery technology or technology under development, regulatory and environmental approval, the availability of markets and production facilities and political risk to the development. The Corporation will be required to make substantial capital expenditures in order to prove, exploit, develop and produce oil and natural gas from its resource properties in the future. If the Corporation's cash flow from operations is not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or, if available, that the terms will be acceptable to the Corporation. Failure to obtain such financing on a timely basis could cause the Corporation to forfeit its interest in certain properties, miss certain opportunities, reduce its pace of development or terminate its operations on such properties. An inability of the Corporation to access sufficient capital for its exploration and development purposes could have a material adverse effect on the Corporation's ability to execute its business strategy to develop its prospects.

The significant economic factors that affect the Corporation's future development of its resources are:

- future commodity prices for oil and natural gas (and the Corporation's outlook relating to such prices);
- the future capital costs of drilling, completing, tying in and equipping the wells necessary to develop such lands at the relevant times;
- the future costs of operating wells at the relevant times; and
- the levels of royalties applicable to productions from such lands.

The significant uncertainties that affect the Corporation's development of its resources are:

- the ability of the Corporation to obtain the capital necessary to fund the development of such lands at the relevant times;
- the future drilling and completion results the Corporation achieves in its development activities (e.g. with respect to the development of particular intervals or geographic areas, the uncertainty would be whether the initial drilling and completion results are sufficient to justify the development of such interval or geographic area);
- drilling and completion results achieved by others on lands in proximity to the Corporation's lands;
- transportation and processing infrastructure becoming available in a timeline consistent with proposed development plans;
- the availability of regulatory approvals for development of the lands and the necessary infrastructure; and
- governmental actions and future changes to applicable regulatory or royalty regimes that affect timing or economics of proposed development activities.

Significant risk factors specific to Birchcliff and the projects outlined herein include the following:

- Commodity prices have been and are expected to remain volatile. Sustained low prices may compel the Corporation to re-evaluate its development plans and reduce or eliminate various projects with marginal economics. Birchcliff will need to be satisfied that its forecast of future industry and economic conditions and commodity prices prevailing during and after the applicable development project is sufficient to justify proceeding with the development of such project.

- The actual operating and other costs may vary materially from the costs assumed by Deloitte. For example, the operating costs for the Elmworth area assumed by Deloitte were based on the field operating costs for the nearby, analogous Pouce Coupe area. If actual operating or other costs vary materially from those assumed by Deloitte, this would have an impact on the economics of the applicable project and could delay development.

- If the facilities and infrastructure do not expand in the manner and in the time frame assumed by Deloitte, this would have an impact on the development schedules for Birchcliff's resource projects and such projects could be delayed. In addition, the Gordondale Gas Plant is owned, and the Assumed Shallow-Cut Plant will be owned, by a third party which the Corporation does not control.

- The Corporation's development activities are dependent on the availability of equipment, materials (including those needed for fracturing operations) and skilled personnel. Demand for such limited equipment, materials and skilled personnel may affect the availability of such equipment, materials and skilled personnel to the Corporation and may delay the Corporation's development activities. During times of high demand, the costs of such equipment, materials and personnel may increase, resulting in increased costs to the Corporation.

- The implementation of new regulations or the modification of existing regulations regarding hydraulic fracturing or GHG/methane emissions may have a material adverse impact on the Corporation's ability to develop its resources. Any new laws, regulations or permitting requirements regarding hydraulic fracturing or GHG/methane emissions could lead to operational delays, increased operating costs, third party or governmental claims and could increase the Corporation's costs of compliance and doing business. All of the foregoing could delay development.

All of these risks and uncertainties have the potential to delay the development of Birchcliff's resources. On the other hand, uncertainty as to the timing and nature of the evolution of better exploration, drilling, completion and production technologies have the potential to accelerate development activities and enhance the economics relating to the development of such resources.

There are no unusually significant abandonment and reclamation costs associated with the resources.

Positive and Negative Factors Relevant to the Estimates

Significant positive factors relevant to the estimates of Birchcliff's resources include:

- Birchcliff's and offsetting competitor wells with production history from the same zones;

- the same drilling and completion techniques are intended to be used by Birchcliff to develop these resources; and

- Birchcliff's strong record of developing similar development projects according to its plans.

Significant negative factors relevant to the estimate of Birchcliff's resources include:

- current limitations in take-away/midstream capacity to deliver the resources to market;

- uncertainty in assumptions about the geometry of hydraulic fracture stimulations and associated recovery factors; and

- low pressure areas with potential production deliverability issues. This is applicable to the Corporation's D4, D5 only, BD/DoigP only and BD/D5/DoigP contingent resource projects in Gordondale, the Corporation's D3, D4, D5 only, BD/DoigP only and BD/D5/DoigP prospective resource projects in Gordondale and all of the Corporation's prospective resource projects in the Grande Prairie and Saddle Hills areas.

APPENDIX B

FORM 51-101F2
REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

To the Board of Directors of Birchcliff Energy Ltd. (the "**Company**"):

1. We have evaluated the Company's reserves data as at December 31, 2018. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2018, estimated using forecast prices and costs.

2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the "**COGE Handbook**") maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).

4. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

5. The following table shows the net present value of future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated for the year ended December 31, 2018, and identifies the respective portions thereof that we have evaluated and reported on to the Company's Board of Directors:

			Net Present Value of Future Net Revenue (before income taxes, 10% discount rate)			
Independent Qualified Reserves Evaluator or Auditor	**Effective Date of Evaluation Report**	**Location of Reserves (Country or Foreign Geographic Area)**	**Audited $M**	**Evaluated $M**	**Reviewed $M**	**Total $M**
Deloitte LLP	Birchcliff Energy Ltd. Reserve estimation and economic evaluation – Corporate properties less Gordondale December 31, 2018	Canada	-	4,037,876.1	-	4,037,876.1
Deloitte LLP	Birchcliff Energy Ltd. Reserve estimation and economic evaluation – Corporate Contracts & Abandonments December 31, 2018	Canada	-	387,298.4	-	387,298.4
McDaniel & Associates Consultants Ltd.	Birchcliff Energy Ltd. Reserve estimation and economic evaluation – Gordondale property December 31, 2018	Canada	-	1,716,225.5	-	1,716,225.5
Total			-	6,141,399.9	-	6,141,399.9

6. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

7. We have no responsibility to update our reports referred to in paragraph 5 for events and circumstances occurring after the effective date of our reports.

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

Executed as to our report referred to above:

Deloitte LLP 700, 850 – 2nd Street S.W. Calgary, Alberta T2P 0R8	*Original signed by: "Robin G. Bertram"* Robin G. Bertram, P. Eng. Partner Execution date: February 13, 2019
McDaniel & Associates Consultants Ltd. 2200, 555 – 5th Avenue S.W. Calgary, Alberta T2P 3G6	*Original signed by: "Brian Hamm"* Brian Hamm, P. Eng. President & CEO Execution date: February 13, 2019

FORM 51-101F2
REPORT ON CONTINGENT RESOURCES DATA AND PROSPECTIVE RESOURCES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

To the Board of Directors of Birchcliff Energy Ltd. (the "**Company**"):

1. We have evaluated the Company's contingent resources data and prospective resources data as at December 31, 2018. The contingent resources data and prospective resources data are risked estimates of volume of contingent resources and prospective resources and related risked net present value of future net revenue as at December 31, 2018, estimated using forecast prices and costs.

2. The contingent resources data and prospective resources data are the responsibility of the Company's management. Our responsibility is to express an opinion on the contingent resources data and prospective resources data based on our evaluation.

3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the "**COGE Handbook**") maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).

4. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the contingent resources data and prospective resources data are free of material misstatement. An evaluation also includes assessing whether the contingent resources data and prospective resources data are in accordance with principles and definitions presented in the COGE Handbook.

5. The following tables set forth the risked volume and risked net present value of future net revenue of contingent resources and prospective resources (before deduction of income taxes) attributed to contingent resources and prospective resources, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the Company's statement prepared in accordance with Form 51-101F1 and identifies the respective portions of the contingent resources data and prospective resources data that we have evaluated and reported on to the Company's Board of Directors:

Classification	Independent Qualified Reserves Evaluator or Auditor	Effective Date of Evaluation Report	Location of Resources Other than Reserves (Country or Foreign Geographic Area)	Risked Volume (Bcfe)	Risked Net Present Value of Future Net Revenue (before income taxes, 10% discount rate) Audited $M	Evaluated $M	Total $M
Development Pending Contingent Resources (2C)	Deloitte LLP	December 31, 2018	Canada	8,037.1	-	1,607,815.9	1,607,815.9

Classification	Independent Qualified Reserves Evaluator or Auditor	Effective Date of Evaluation Report	Location of Resources Other than Reserves (Country or Foreign Geographic Area)	Risked Volume (Bcfe)
Prospective Resources (Best Estimate) – Prospect	Deloitte LLP	December 31, 2018	Canada	5,121.3
Contingent Resources (2C)	Deloitte LLP	December 31, 2018	Canada	
Development On Hold				2,060.6
Development Unclarified				149.2
Development Not Viable				31.3

6. In our opinion, the contingent resources data and prospective resources data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. We express no opinion on the contingent resources data and prospective resources data that we reviewed but did not audit or evaluate.

7. We have no responsibility to update our reports referred to in paragraph 5 for events and circumstances occurring after the effective date of our reports.

8. Because the contingent resources data and prospective resources data are based on judgments regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

Deloitte LLP
700, 850 – 2nd Street S.W.
Calgary, Alberta
T2P 0R8

Original signed by: "Robin G. Bertram"
Robin G. Bertram, P. Eng.
Partner

Execution date: March 13, 2019

APPENDIX C

FORM 51-101F3
REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

Management of Birchcliff Energy Ltd. (the "**Company**") are responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data and includes other information such as contingent resources data and prospective resources data.

Independent qualified reserves evaluators have evaluated the Company's reserves data, contingent resources data and prospective resources data. The reports of the independent qualified reserves evaluators will be filed with securities regulatory authorities concurrently with this report.

The Reserves Evaluation Committee of the Board of Directors of the Company has:

(a) reviewed the Company's procedures for providing information to the independent qualified reserves evaluators;

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

(c) reviewed the reserves data, contingent resources data and prospective resources data with management and the independent qualified reserves evaluators.

The Reserves Evaluation Committee of the Board of Directors has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The Board of Directors has, on the recommendation of the Reserves Evaluation Committee, approved:

(a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data, contingent resources data and prospective resources data and other oil and gas information;

(b) the filing of the Form 51-101F2s which are the reports of the independent qualified reserves evaluators on the reserves data, contingent resources data and prospective resources data; and

(c) the content and filing of this report.

Because the reserves data, contingent resources data and prospective resources data are based on judgments regarding future events, actual results will vary and the variations may be material.

(signed) *"A. Jeffery Tonken"*
President and Chief Executive Officer

(signed) *"Christopher A. Carlsen"*
Vice-President, Engineering

(signed) *"James W. Surbey"*
Director and Chairman of the
Reserves Evaluation Committee

(signed) *"Dennis A. Dawson"*
Director and Member of the
Reserves Evaluation Committee

March 13, 2019

APPENDIX D

AUDIT COMMITTEE CHARTER

Purpose

The purpose of the Audit Committee (the "**Committee**") of the board of directors (the "**Board**") of Birchcliff Energy Ltd. (the "**Corporation**") is to assist the Board in overseeing:

(a) the preparation of the financial statements of the Corporation and the conduct of any audit thereof;

(b) the Corporation's compliance with applicable financial reporting requirements; and

(c) the independence and performance of the Auditor.

Definitions

For the purposes of this Charter, the following terms have the following meanings:

(a) "**Auditor**" means the auditor appointed to prepare an audit report in respect of the annual financial statements of the Corporation.

(b) "**NI 52-110**" means National Instrument 52-110 – *Audit Committees* promulgated by the securities regulatory authorities in Canada as may be amended from time to time.

Composition of the Committee

(a) Number of Members: The Committee shall be composed of a minimum of three members, each of whom shall be a member of the Board.

(b) Independence of Members: Each member of the Committee shall be "independent" within the meaning of NI 52-110 unless the Board determines to rely on an exemption contained in NI 52-110.

(c) Financial Literacy: Each member of the Committee shall be "financially literate" within the meaning of NI 52-110 unless the Board determines to rely on an exemption contained in NI 52-110.

(d) Appointment and Vacancies: The members of the Committee shall be appointed by the Board and shall serve at the pleasure of the Board. Any member of the Committee may be removed or replaced at any time by the Board and shall automatically cease to be a member of the Committee as soon as such member ceases to be a director of the Corporation. The Board may fill vacancies on the Committee by appointment from among its members. If and whenever a vacancy shall exist on the Committee, the remaining members may exercise all of its powers so long as a quorum remains.

(e) Chair: The Board shall designate one member of the Committee as the chairperson of the Committee (the "**Chair**"). The Chair shall preside over all meetings of the Committee, and in the Chair's absence, the members of the Committee may designate from among such members the Chair for the purpose of such meeting.

Transaction of Business and Meetings

(a) Transaction of Business: The Committee shall transact its business in accordance with governing corporate legislation and the provisions of the by-laws of the Corporation. To the extent not provided either therein or in the provisions of this Charter, the Committee may determine the manner in which it will transact its business by way of resolution passed by a majority of votes cast thereon.

(b) Number of Meetings: The Committee shall meet at least four times per year or more frequently as is necessary to carry out its duties and responsibilities.

(c) Calling of Meetings: The Chair or any member of the Committee may at any time convene a meeting of the Committee. Upon a request from the Auditor, the Chair shall convene a meeting of the Committee to consider any matters that the Auditor desires to bring to the attention of the Committee.

(d) Notice of Meetings: Notice of meetings shall be delivered, mailed, faxed, emailed or sent by any other form of transmitted or recorded message to each member of the Committee not less than forty-eight hours before the meeting is to take place. Notice of any meeting or any irregularity thereof may be waived by any member. Meetings may be held at any time without formal notice if all the members are present, or if a quorum is present and those members who are absent have signified their consent to the meeting being held in their absence. Any resolution passed or action taken at such a meeting shall be valid and effectual as if it had been passed or taken at a meeting duly called and constituted.

(e) Quorum: A quorum for meetings of the Committee shall be at least two members of the Committee. No business may be transacted by the Committee at a meeting unless a quorum of the Committee is present.

(f) Voting: All motions made at a meeting of the Committee shall be decided by a simple majority of votes cast by members of the Committee who vote on such motion. In the event of an equality of votes on any motion, the Chair shall not have a second or casting vote.

(g) Minutes and Reporting to the Board: Minutes shall be prepared of all meetings of the Committee. A copy of such minutes shall be circulated to all members of the Committee and the Board. In addition, the Chair may report orally to the Board on any matter in his or her view requiring the immediate attention of the Board.

(h) Attendance of Non-Members: The Committee may invite to a meeting any officers, directors or employees of the Corporation, legal counsel, advisors and other persons whose attendance it considers necessary or desirable in order to carry out its duties and responsibilities. If not a member of the Committee, such invitees shall have no voting rights at any meeting of the Committee.

Duties and Responsibilities

External Auditor

(a) The Committee shall recommend to the Board:

   (i) the person or firm to be nominated as Auditor for the purposes of preparing or issuing an auditor's report or performing other audit, review or attest services for the Corporation; and

   (ii) the compensation of the Auditor.

(b) The Committee is authorized in carrying out its duties to communicate directly with the Auditor and the Auditor shall report directly to the Committee. The Committee shall be directly responsible for overseeing the work of the Auditor engaged for the purpose of preparing or issuing an auditor's report or performing other audit, review or attest services for the Corporation, including the resolution of disagreements between management and the Auditor regarding financial reporting.

(c) The Committee shall review and recommend to the Board the annual audit plan of the Auditor and the terms of the Auditor's engagement, including the appropriateness and reasonableness of the Auditor's fees.

(d) The Committee may review and evaluate the Auditor's performance.

(e) The Committee shall review and receive assurances as to the independence of the Auditor.

(f) The Committee shall review any reports issued by the Canadian Public Accountability Board which specifically relate to any previous audit of the financial statements of the Corporation.

(g) The Committee shall periodically meet with the Auditor without management present to discuss the completeness and accuracy of the Corporation's financial statements.

(h) When there is to be a change in the Auditor, the Committee shall review the issues related to the change and shall approve the information to be included in the notice of such change required to be filed with the applicable regulatory authorities.

(i) The Committee shall pre-approve all non-audit services to be provided to the Corporation (or its subsidiary entities, if any) by the Auditor. The Committee may delegate this function to one of its independent members, who shall report to the Committee on any such approvals.

Financial Reporting and Public Disclosure

(j) The Committee shall review, report to the Board on and, if deemed advisable by the Committee, recommend to the Board for approval, the Corporation's interim and annual financial statements and all related management's discussion and analysis before those materials are filed with the applicable regulatory authorities and publicly disclosed. If authorized by the Board, the Committee may approve the interim financial statements and the related management's discussion and analysis, before those materials are filed with the applicable regulatory authorities and publicly disclosed. The Committee shall receive and review any reports prepared by management of the Corporation or the Auditor that relate to any of the following:

  (i) changes in accounting principles, or in their application, which may have a material impact on a current or future year's financial statements;

  (ii) significant accruals, reserves or other estimates, such as ceiling test calculations;

  (iii) the accounting treatment of significant, unusual or non-recurring transactions;

  (iv) disclosures of commitments and contingencies;

  (v) adjustments raised by the Auditor, whether or not included in the financial statements;

  (vi) unresolved differences between management and the Auditor;

  (vii) explanations of significant variances with comparative reporting periods; and

  (viii) related party transactions and ensuring that the nature and extent of such transactions are properly disclosed.

(k) The Committee shall review, report to the Board on and, if deemed advisable by the Committee, recommend for approval by the Board, the Corporation's annual and interim earnings press releases before the Corporation publicly discloses this information.

(l) As it relates to financial information that is extracted or derived from the Corporation's financial statements, the Committee shall review, report to the Board on and, if deemed advisable by the Committee, recommend for approval by the Board, all annual reports, annual information forms, information circulars, business acquisition reports, prospectuses and other securities offering documents (excluding, for greater certainty, the Corporation's corporate presentations) before such documents are publicly disclosed and, if applicable, filed with the applicable regulatory authorities.

(m) The Committee shall ensure that adequate procedures are in place for the review of the Corporation's public disclosure of financial information extracted or derived from the Corporation's financial statements and shall periodically assess the adequacy of those procedures.

Internal Controls

(n) The Committee shall oversee management's reporting on internal controls and shall advise the Board of any material failures of the internal controls.

(o) The Committee shall establish procedures:

(i) for the receipt, retention and treatment of complaints received by the Corporation regarding accounting, internal accounting controls, or auditing matters; and

(ii) for the confidential, anonymous submission by employees of the Corporation of concerns regarding questionable accounting or auditing matters.

Other Duties and Responsibilities

(p) The Committee shall review management's reports regarding the certification of annual and interim financial reports in accordance with applicable securities legislation.

(q) The Committee shall review and approve:

(i) the Corporation's hiring policies regarding partners, employees and former partners and employees of the present and former Auditor; and

(ii) the employment by the Corporation of any current or former partner or employee of the present and former Auditor.

(r) The Committee shall review, at least annually, this Charter and recommend to the Board any amendments to this Charter that the Committee considers necessary or advisable.

(s) The Committee shall bring to the attention of the Board such other issues as are necessary to carry out its mandate and shall make recommendations to the Board with respect to the foregoing. In addition, the Committee shall review and report to the Board on any other matters as may be delegated to it by the Board from time to time.

Access to Information and Advisors

(a) In discharging its role, the Committee shall have full access to all books, records, facilities and personnel of the Corporation to the extent that the same relate to matters that are the responsibility of the Committee under this Charter. The Committee may require the Auditor or any director, officer or employee of the Corporation to appear before it to discuss the accounts and records and/or financial position of the Corporation. Members of the Committee may rely upon the accuracy of any statement or report prepared by the Auditor or upon any other statement or report including any appraisal report prepared by a qualified person and shall not be responsible or held liable for any loss or damage in respect of any action taken on the basis of such statement or report.

(b) The Committee has the authority to engage such advisors (including independent legal counsel) as it considers necessary or desirable to assist it in fulfilling its duties and responsibilities as provided in this Charter and to set the compensation to be paid thereto, such engagement to be at the Corporation's expense. The Corporation shall be responsible for all other expenses of the Committee that are deemed necessary or desirable by the Committee in order to fulfil its duties and responsibilities as provided for in this Charter.

Approved and Adopted: March 14, 2018.