PENGROWTH

Pengrowth Energy Corporation

2018 Annual Information Form

March 5, 2019

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Unless otherwise indicated, all of the information provided in this Annual Information Form is as at December 31, 2018

GLOSSARY OF TERMS AND ABBREVIATIONS

The following terms in this Annual Information Form ("**AIF**") have the meanings set forth below:

"**2010 Note Purchase Agreements**" means, collectively, the separate and several note purchase agreements dated May 11, 2010 among us and the purchasers listed therein, as amended;

"**2010 Senior Notes**" means the US$115.5 million (original issue amount) of senior unsecured notes issued under the 2010 Note Purchase Agreements;

"**2012 Note Purchase Agreements**" means, collectively, the separate and several note purchase agreements dated October 18, 2012 among us and the purchasers listed therein, as amended;

"**2012 Senior Notes**" means the US$335 million, £15 million and $25 million (original issue amounts) of senior unsecured notes collectively issued under the 2012 Note Purchase Agreements;

“a**bandonment and reclamation costs**” means all costs associated with the process of restoring a property that has been disturbed by oil and gas activities to a standard imposed by applicable government or regulatory authorities;

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

"**Audit Committee"** means the audit and risk committee of the Board of Directors;

“**Best Estimate**” is a best estimate of the quantity of oil or gas that will be recovered from the accumulation, which under probabilistic methodology reflects a 50% confidence level;

“**bitumen**” means a naturally occurring solid or semi-solid hydrocarbon: (a) consisting mainly of heavier hydrocarbons, with a viscosity greater than 10,000 mPa-s or 10,000 cP measured at the hydrocarbon’s original temperature in the reservoir and at atmospheric pressure on a gas-free basis, and (b) that is not primarily recoverable at economic rates through a well without the implementation of enhanced recovery methods;

"**Board**" or "**Board of Directors**" refers to our board of directors;

“**by-product**” means a substance that is recovered as a consequence of producing a product type;

"**CCAA**" means the *Companies' Creditors Arrangement Act* (Canada);

"**coal bed methane**" means natural gas that: (a) primarily consists of methane, and (b) is contained in a coal deposit;

“**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 our common shares;

“**Company Interest**” is equal to our gross interest plus our Royalty Interest; that is, the Working Interest share of production or reserves prior to the deduction of royalties plus any Royalty Interest in production or reserves at the wellhead;

“**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. The contingencies may include factors such as economics, legal, environmental, political, regulatory or lack of markets. Contingent Resources are classified in accordance with the level of certainty associated with the estimates and further sub-classified and risked according to their project maturity and chance of development. Contingent Resources do not constitute, and should not be confused with, reserves;

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

"**Corporation**" and "**Pengrowth**", "**we**", "**us**" **and** "**our**" refers to Pengrowth Energy Corporation and all of our wholly-owned direct and indirect subsidiary entities on a consolidated basis as well as our predecessors, Pengrowth Corporation and Pengrowth Energy Trust;

"**Credit Facility**" refers to Pengrowth's $330 million Amended and Restated Credit Agreement dated October 12, 2017 among Pengrowth and a syndicate of eleven financial institutions;

"**Developed Non-Producing Reserves**" refers to 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;

"**Developed Producing Reserves**" refers to 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 Reserves**" refers to 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;

"**Future Development Costs**" or "**FDC**" refers to the amount of capital estimated by the independent evaluator that will be required to maintain production or bring non-producing, undeveloped or probable reserves on stream;

"**Future Net Revenue**" means a forecast of revenue, estimated using forecast prices and costs or constant prices and costs, arising from the anticipated development and production of resources, net of the associated royalties, operating costs, development costs and abandonment and reclamation costs;

"**GLJ**" refers to GLJ Petroleum Consultants Ltd., independent petroleum consultants, in Calgary, Alberta;

"**GLJ Report**" refers to the reserve report prepared by GLJ dated February 27, 2019 with an effective date of December 31, 2018;

"**gross**" with respect to: (i) our interest in production or reserves, refers to our Working Interest share (operated or non-operated) before the deduction of royalties and without including any of our Royalty Interests; (ii) our wells, refers to the total number of wells in which we have an interest; and (iii) our properties, refers to the total area of properties in which we have an interest;

"**heavy crude oil**" means crude oil with a relative density greater than 10 ^{o}API and less than or equal to 22.3 ^{o}API;

"**High Estimate**" is an optimistic estimate of the quantity of oil or gas that will be recovered from the accumulation, which under probabilistic methodology reflects a ten percent confidence level;

"**hydrocarbon**" means a compound consisting of hydrogen and carbon, which, when naturally occurring, may also contain other elements such as sulphur;

"**Instantaneous Steam-Oil Ratio**" or "**ISOR**" refers to the efficiency of a steam injection recovery process and is the measure of the volume of steam, in equivalent barrels of water, required to produce one barrel of bitumen, currently or at any time;

"**Koch**" means Koch Oil Sands Operating ULC;

"**light crude oil**" means crude oil with a relative density greater than 31.1 ^{o}API;

"**Low Estimate**" is a conservative estimate of the quantity of oil or gas that will be recovered from the accumulation, which under probabilistic methodology reflects a 90% confidence level;

"**medium crude oil**" means crude oil with a relative density greater than 22.3 ^{o}API and less than or equal to 31.1 ^{o}API;

"**natural gas**" means a naturally occurring mixture of hydrocarbon gases and other gases;

"**natural gas liquids**" or "**NGL**" means those hydrocarbon components that can be recovered from natural gas as a liquid including, but not limited to, ethane, propane, butanes, pentanes plus, and condensates;

"**net**" with respect to: (i) our interest in production or reserves, refers to our Working Interest share (operated or non-operated) after the deduction of royalty obligations, plus our Royalty Interests in production or reserves; (ii) our interest in wells, refers to the number of wells obtained by aggregating our Working Interest in each of our gross wells; and (iii) our interest in a property, refers to the total area in which we have an interest multiplied by the Working Interest owned by us;

"**NI 51-101**" means National Instrument 51-101-Standards of Disclosure for Oil and Gas Activities of the Canadian Securities Administrators;

"**NI 51-102**" means National Instrument 51 102 -Continuous Disclosure Obligations of the Canadian Securities Administrators;

"**NI 52-110**" means National Instrument 52-110 -Audit Committees of the Canadian Securities Administrators;

"**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 Proved Plus Probable plus Possible 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;

"**Probable Undeveloped Reserves**" refers to those Probable Reserves that are Undeveloped Reserves;

"**Proved Developed Non-Producing Reserves**" refers to those Proved Reserves that are Developed Non-Producing Reserves;

"**Proved Developed Producing Reserves**" refers to those Proved Reserves that are Developed Producing Reserves;

"**Proved Developed Reserves**" refers to those Proved Reserves that are Developed Reserves;

"**Proved Reserves**" are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated Proved Reserves;

"**Proved Undeveloped Reserves**" refers to those Proved Reserves that are Undeveloped Reserves;

"**Recycle Ratio**" refers to the ratio resulting from the quotient of operating netback and F&D or FD&A Costs;

"**Reserve Life Index**" or "**RLI**" refers to the number of years determined by dividing Company Interest reserves of a property by the next year's forecast Company Interest production for the corresponding reserve category from such property. The reserves and next year's forecast production for such property come from the GLJ Report;

"**reserves**" refers to 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: (i) analysis of drilling, geological, geophysical and engineering data; (ii) the use of established technology; and (iii) specified economic conditions which are generally accepted as being reasonable and shall be disclosed; reserves are classified according to the degree of certainty associated with the estimate (e.g., proved, probable);

"**risked**" means adjusted for the probability of loss or failure in accordance with the COGE Handbook;

"**Royalty Interest(s)**" refers to Pengrowth's interest in production and payment that is based on the gross production at the wellhead. A royalty is paid in either cash or kind, but is paid on a value calculated at the wellhead;

"**shale gas**" means natural gas (a) 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 (b) that usually requires the use of hydraulic fracturing to achieve economic production rates;

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

"**Tax Act**" refers to the *Income Tax Act* (Canada) and the regulations thereunder, as amended from time to time; and

"**Term Notes**" means, collectively, the 2010 Senior Notes and the 2012 Senior Notes.

"**Total Proved Plus Probable Reserves**" or "**P+P**" means the aggregate of Proved Reserves and Probable Reserves;

"**Undeveloped Reserves**" refers to those reserves expected to be recovered from known accumulations where a significant expenditure (e.g. the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable, possible) to which they are assigned; and

"**Working Interest**" refers to the percentage of undivided interest, excluding Royalty Interests, held by Pengrowth in an oil and gas property.

Abbreviations

"**$M**" and "**$MM**" refers to thousands of dollars and millions of dollars, respectively;

"**AECO**" refers to AECO/NIT, the Alberta natural gas benchmark price;

"**AER**" refers to the Alberta Energy Regulator;

"**API**" refers to the American Petroleum Institute;

"**°API**" refers to an indication of the specific gravity of crude oil measured on the API gravity scale;

"**bbl**", "**Mbbl**" and "**MMbbl**" refers to barrels, thousands of barrels and millions of barrels, respectively;

"**bbl/d**" refers to barrels per day;

"**BOE**", "**Mboe**" and "**MMboe**" refers to barrels of oil equivalent, thousands of barrels of oil equivalent and millions of barrels of oil equivalent, respectively, on the basis of one BOE being equal to one barrel of oil or NGL or six Mcf of natural gas;

"**BOE/d**" refers to barrels of oil equivalent per day;

"**CBM**" refers to natural gas, primarily methane, producible from coal seams, commonly called coal bed methane;

"**Cdn$**" or "**$**" refers to Canadian dollars;

"**CO_2**" refers to carbon dioxide which is a gas at room temperature and pressure. However, at higher pressures, such as those used in EOR miscible floods, carbon dioxide is a liquid;

"**cP**" refers to centipoise, a unit measure of viscosity;

"**CSOR**" refers to the efficiency of a steam injection recovery process and is a measure of the cumulative volume of steam, in equivalent barrels of water, required to produce a cumulative volume of bitumen as of the same point in time;

"**EDGAR**" refers to the Electronic Data Gathering Analysis and Retrieval System maintained by the SEC;

"EOR" refers to enhanced oil recovery;

"EPEA" means the *Environmental Protection and Enhancement Act* (Alberta), RSA 2000, c E-12, as amended, including the regulations promulgated thereunder;

"**F&D Costs**" refers to finding and development costs;

"**FD&A Costs**" refers to finding, development and acquisition costs;

"**FDC**" refers to Future Development Costs;

"**GHG**" refers to greenhouse gas;

"**H_2S**" refers to hydrogen sulphide gas;

"**IFRS**" refers to International Financial Reporting Standards;

"**ISOR**" refers to Instantaneous Steam Oil Ratio;

"**km**" means kilometres;

"**Mcf**", "**MMcf**" and "**Bcf**" refers to thousands of cubic feet, millions of cubic feet and billions of cubic feet, respectively;

"**McfGE**" refers to thousand cubic feet of gas equivalent on the basis of one barrel of oil or one barrel of NGL being equal to six Mcf of natural gas;

"**Mcf/d**" and "**MMcf/d**" refers to thousands of cubic feet per day and millions of cubic feet per day, respectively;

"**MMBtu**" refers to million British thermal units;

"**mPa-s**" refers to millipascal-second, a derived metric system international measurement unit of dynamic viscosity;

"**MW**" refers to megawatts;

"**NGL**" refers to natural gas liquids;

"**NYSE**" refers to the New York Stock Exchange;

"**P+P**" refers to Total Proved Plus Probable Reserves;

"**RLI**" refers to Reserve Life Index;

"**SAGD**" refers to steam assisted gravity drainage;

"**SEC**" refers to the United States Securities and Exchange Commission;

"**SEDAR**" refers to the System for Electronic Document Analysis and Retrieval of the Canadian Securities Administrators;

"**TSX**" refers to the Toronto Stock Exchange;

"**US**" or "**United States"** refers to the United States of America;

"**US$**" refers to United States dollars;

"**US GAAP**" refers to United States generally accepted accounting principles;

"**WCS**" refers to Western Canada Select;

"**WCSB**" refers to the Western Canadian Sedimentary Basin; and

"**WTI**" refers to West Texas Intermediate crude oil.

CONVERSION

In this AIF, measurements are given in standard imperial or metric units. The following table sets forth certain standard conversions:

To Convert From	To	Multiply by
Mcf	cubic metre	28.174
Mcf	BOE	0.1667
bbl	BOE	1.0
MMBtu	gigajoule	1.0546
cubic metre	bbl	6.29
metre	feet	3.281
mile	kilometre	1.609
hectare	acre	2.471

ADVISORIES

The information in this AIF is stated as at December 31, 2018 unless otherwise indicated. For additional information and details, readers are referred to the audited consolidated financial statements for the year ended December 31, 2018 and notes that follow, as well as the accompanying annual Management's Discussion and Analysis, which are available on SEDAR at www.sedar.com.

CONVERSION OF NATURAL GAS TO BARRELS OF OIL EQUIVALENT

Disclosure provided herein in respect of a BOE and an McfGE may be misleading, particularly if used in isolation. A BOE conversion ratio of six (6) Mcf of natural gas to one barrel of oil and an McfGE conversion ratio of one barrel of oil to six (6) Mcf of natural gas 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 equivalent of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.**

PRESENTATION OF OUR FINANCIAL INFORMATION

Financial information in this AIF has been prepared in accordance with International Financial Reporting Standards ("**IFRS**"). IFRS differs in some significant respects from United States generally accepted accounting principles ("**US GAAP**") and thus our financial statements may not be comparable to the financial statements of companies following US GAAP.

Unless otherwise stated, all sums of money referred to in this AIF are expressed in Canadian dollars.

PRESENTATION OF OUR RESERVE AND RESOURCE INFORMATION

National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* ("**NI 51-101**") of the Canadian Securities Administrators permits oil and gas issuers, in their filings with Canadian securities regulators, to disclose not only Proved Reserves but also Probable Reserves, Possible Reserves and Contingent Resources, and to disclose reserves and production on a gross basis before deducting royalties. Probable Reserves and Possible Reserves are of a higher risk and are less likely to be accurately estimated or recovered than Proved Reserves. Contingent Resources are higher risk than Probable Reserves and Possible Reserves and are less likely to be accurately estimated or recovered than Probable Reserves or Possible Reserves. Because we are permitted to prepare this AIF in accordance with Canadian disclosure requirements, we have disclosed in this AIF resources designated as Probable Reserves, Possible Reserves and Contingent Resources and have disclosed reserves and production on a gross basis before deducting royalties.

Current SEC reporting requirements permit oil and gas companies to disclose Probable Reserves and Possible Reserves, in addition to the required disclosure of Proved Reserves. If this AIF was required to be prepared in accordance with US disclosure requirements, the SEC's requirements would prohibit Contingent Resources from being disclosed. Under current SEC requirements, net quantities of reserves are required to be disclosed, which requires disclosure on an after royalties basis and does not include reserves relating to the interests of others. For a description of these and additional differences between Canadian and US standards of reporting reserves, see "*Risk Factors - Other Risks - Canadian and United States practices differ in reporting reserves and production and our estimates may not be comparable to those of companies in the United States*". Additional information prepared in accordance with the US Financial Accounting Standards Board's Accounting Standards Update (Extractive Activities-Oil and Gas (Topic 932)) relating to our oil and gas reserves is set forth in our current Form 40-F, which is available through EDGAR at the SEC's website at www.sec.gov.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION AND STATEMENTS

This AIF contains forward-looking information and statements (collectively, “forward-looking statements”) within the meaning of applicable Canadian and US securities laws and other information based on Pengrowth’s current expectations, estimates, projections and assumptions that were made by the Corporation in light of information available at the time the statement was made and considering Pengrowth’s experience and historical trends. Forward-looking statements are often, but not always, identified by the use of words such as “anticipate”, “believe”, “expect”, “plan”, “intend”, “forecast”, “target”, “project”, “guidance”, “may”, “will”, “should”, “could”, “estimate”, “predict” or similar words suggesting future outcomes or language suggesting an outlook. Forward-looking statements are based on our current expectations as well as assumptions made by, and information currently available to, us concerning anticipated financial performance, business prospects, strategies, regulatory developments, future bitumen, oil and natural gas commodity prices and differentials between light crude oil, medium crude oil and heavy crude oil prices, future oil and natural gas production levels, future interest and foreign exchange rates, the cost of expanding our property holdings, our ability to obtain equipment in a timely and cost-effective manner to carry out development activities, our ability to market our oil and gas successfully to current and new customers, the impact of increasing competition, our ability to obtain financing on acceptable terms, and our ability to add production and reserves through our acquisition, development and exploration activities. Although management of the Corporation considers these expectations and assumptions to be reasonable based on information currently available to it, they may prove to be incorrect. Many factors could cause the Corporation’s actual results to differ materially from those expressed or implied in any forward-looking statements made by, or on behalf of, the Corporation.

In particular, forward-looking statements included in this AIF include, but are not limited to, statements with respect to:

- Pengrowth’s strategy, business plans and goals, and expectations about the cost and development of certain projects;
- performance of the Corporation’s assets, including production volumes and the costs of planned capital expenditures;
- Pengrowth’s capital expenditure and investment programs and the timing and results therefrom;
- the size of, and future net revenues from, oil and gas reserves;
- the performance characteristics of the Corporation’s oil and gas properties;
- supply and demand for oil and natural gas;
- drilling inventory, drilling plans and timing of drilling, completion and tie-in of wells;
- results of various projects of the Corporation;
- results of operations;
- production, future costs, reserves and production estimates;
- timing of development of undeveloped reserves;
- access to and costs relating to use of facilities and infrastructure;
- financial condition, access to capital and overall financial strategy;
- financial and business prospects and financial outlook;
- treatment under governmental regulatory regimes and tax laws;
- estimates of future net revenues, commodity price forecasts, currency, exchange and interest rate expectations and production estimates;
- the existence, operation and strategy of the Corporation’s commodity price risk management program;
- oil and natural gas production levels and various factors that may impact production levels;
- development activities and costs anticipated to occur or be incurred in 2019, including those identified as Future Development Costs;
- estimated abandonment and reclamations costs and asset retirement obligations;
- anticipated effects of and responses to environmental laws, including climate change laws and estimated compliance costs;
- expectations about changes to laws and the impact thereof;

- the Corporation's business, disposition and acquisition strategy, the criteria to be considered in connection therewith, and the benefits to be derived therefrom;
- future development and growth prospects;
- expectations about royalties, operating costs, general administrative costs, costs of services and other costs and expenses;
- ability to meet current and future obligations;
- expectations about income taxes and their impact on Pengrowth, including the tax horizon and taxability of the Corporation;
- weighting of production between different commodities;
- the ability to obtain equipment, services and supplies in a timely manner to carry out our activities; and
- the ability to market oil and natural gas successfully to current and new customers.

Statements relating to "reserves" or "resources" are by their nature forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the reserves and resources described exist in the quantities predicted or estimated and can profitably be produced in the future. The recovery and reserve estimates of the Corporation's reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. As a consequence, actual results may differ materially from those anticipated in the forward-looking statements.

By their very nature, forward-looking statements involve inherent risks and uncertainties, both general and specific, and risks that predictions, forecasts, projections and other forward-looking statements will not be achieved. We caution readers not to place undue reliance on these statements as a number of important factors could cause the actual results to differ materially from the beliefs, plans, objectives, expectations and anticipations, estimates and intentions expressed in such forward-looking statements. These factors include, but are not limited to: the volatility of commodity prices; production and development costs and capital expenditures; changes in operating costs; operational risks and uncertainties associated with oil and gas activities, including unexpected formations or pressures, premature declines, fires, blow-outs, equipment failures and other accidents; adverse weather conditions which could disrupt output or impact drilling programs; the accuracy and imprecision of reserve estimates and estimates of recoverable quantities of oil, natural gas and NGLs; unforeseen operating problems; pipeline or delivery capacity and constraints; our ability to replace and expand oil and gas reserves; environmental claims and liabilities; incorrect assessments of value when making acquisitions; increases in debt service charges; the loss of key personnel; the marketability of production and demand of our products; defaults by third party operators; unforeseen title defects; fluctuations in foreign currency, exchange rates and interest rates; inadequate insurance coverage; counterparty risk; compliance with environmental laws and regulations; actions by governmental authorities, including the imposition or reassessment of, or changes to, taxes, fees, royalties, duties and other government-imposed compliance costs; changes to laws and government policies that could impact the Corporation's business, including environmental (including climate change and GHG emissions legislation), royalty and tax laws and policies; our ability to access external sources of debt and equity capital; our ability to complete projects on time and on budget; competitive actions from other oil and gas companies or from companies that provide alternative sources of energy; risks and uncertainties associated with obtaining regulatory and stakeholder approval for our operations and exploration and development activities; risks associated with increased activism and public opposition to fossil fuels; risks relating to litigation; and the impact of technology and risks associated with developing and implementing new technologies. Further information regarding these factors may be found under the heading "Risk Factors" in this AIF, under the heading "Business Risks" in our Management's Discussion and Analysis for the year ended December 31, 2018, and in our most recent consolidated financial statements and Form 40-F on file with Canadian securities commissions at www.sedar.com and the SEC at www.sec.gov. Readers are also referred to the risk factors and assumptions described in other documents that Pengrowth files from time to time with securities regulatory authorities, copies of which are available without charge from the Corporation or at www.sedar.com.

The foregoing list of important factors that may affect future results is not exhaustive. When relying on our forward-looking statements to make decisions with respect to Pengrowth, investors and others should carefully consider the foregoing factors and other uncertainties and potential events. Furthermore, the forward-looking statements contained in this AIF are made as of the date of this document and we do not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise, except as required by applicable law. The forward-looking statements contained in this AIF are expressly qualified by this cautionary statement.

■PENGROWTH ENERGY CORPORATION

INTRODUCTION

Pengrowth is a conventional resource developer of Canadian oil and natural gas assets. We are currently focused on growing bitumen production from the Lloydminster formation at our Lindbergh thermal oil project through steam assisted gravity drainage ("**SAGD**").

Pengrowth's 100% owned Groundbirch property in the Montney fairway encompasses 19 sections of land. This project fulfills the Lindbergh project's natural gas needs.

CORPORATE STRUCTURE

The Corporation was incorporated pursuant to the ABCA on October 4, 2010 as 1562803 Alberta Ltd. and changed its name to Pengrowth Energy Corporation on December 2, 2010. The Corporation amalgamated with its wholly-owned subsidiaries NAL Energy Corporation, NAL Properties Inc. and NAL Canada West Inc. on January 1, 2013.

The head office and registered office of the Corporation is located at 1600, 222 - 3rd Avenue S.W., Calgary, Alberta, Canada, T2P 0B4.

As of December 31, 2018 and the date hereof, the Corporation has no subsidiaries.

GENERAL DEVELOPMENT OF THE BUSINESS

Three Year History

A detailed description on the significant developments of the business of the Corporation over the last three completed financial years is set out below.

Financial Year ended December 31, 2018

On November 8, 2018 Pengrowth announced its 2019 Guidance and a Capital Spending Plan of $45 million with the vast majority of this capital allocated to Lindbergh.

On November 8, 2018 Pengrowth announced a 2% increase in its total Proved Reserves, and a 1% increase in its Proved Plus Probable Reserves.

On October 1, 2018, Chandra Henry was appointed to Pengrowth's Board of Directors.

On June 26, 2018 Pengrowth announced its Multi-Year Development Plan which shifted its growth strategy from a large phase 2 build-out to a more incremental approach to make it possible to grow within cash flow. Pengrowth stated that it expects to grow production at Lindbergh to 35,000 bbl per day by 2023. To achieve this, Pengrowth will seek a third party to operate a co-generation facility at Lindbergh to provide both the electricity and steam required for growth. Low-cost proven technologies such as solvents and gases will also be deployed to enhance steam efficiency.

On June 4, 2018 Pengrowth common shares started trading on the OTCQX under the symbol PGHEF.

On June 1, 2018, Pengrowth received its de-listing notification from the New York Stock Exchange ("NYSE").

On April 18, 2018, we announced that we would not take any additional action to come into compliance with NYSE's listing standards but continued to trade on NYSE until the end of the compliance cure period which expired June 1, 2018.

On March 14, 2018, Mr. Peter Sametz succeeded Mr. Derek Evans as President and Chief Executive Officer.

On February 28, 2018, we announced that, as at December 31, 2017, Pengrowth had Total Proved Reserves of 192.7 MMboe and Total Proved plus Probable Reserves of 446.6 MMboe. 99% of Pengrowth's Total Proved plus Probable Reserves at December 31, 2017 were attributable to Lindbergh and Groundbirch reflecting the Company's realignment around these two core assets.

On January 25, 2018, we announced the promotion of Randy Steele to the position of Chief Operating Officer and the departure of Steve De Maio, who was our Senior Vice President, Thermal Operations, since May 2015 and prior thereto, our Vice President, In-Situ Oil Development and Operations.

On January 17, 2018, we announced our 2018 capital program and provided guidance on 2018 expected production and costs. Our 2018 capital budget reflected our plan to spend $65 million in 2018.

Financial Year ended December 31, 2017

On December 21, 2017, we completed the sale of our Quirk Creek assets in Southern Alberta for total cash consideration of $6.5 million, to be received in installments, subject to customary adjustments.

On December 1, 2017, we received notice from the NYSE that our Common Shares, trading under the symbol **PGH**, were no longer in compliance with one of the exchange's continued listing standards resulting from the average closing price of our Common Shares being less than US$1.00 per share over a consecutive 30 trading-day period.

On November 16, 2017 and December 8, 2017, we prepaid an aggregate of approximately $40 million of our Term Notes.

On November 3, 2017, we completed the sale of our remaining Swan Hills assets for $150 million, $12.5 million of which was deferred until June 2018, before customary closing adjustments with the net proceeds used to reduce indebtedness.

On October 23, 2017, we completed the sale of the vast majority of our non-core Alberta legacy assets for nominal cash consideration and the assumption by the purchaser of abandonment and reclamation liabilities.

On October 12, 2017, we prepaid all US$265 million of our outstanding 6.98% 2008 senior notes, all $15 million of our outstanding 6.61% 2008 senior notes and approximately $78 million of remaining senior notes. We also announced that we had finalized the terms of amending agreements with our lenders under our Credit Facility and with the holders of our remaining Term Notes. The amendments included the granting of security over our assets, a substantial reduction in the size of our credit facility and a relaxation of existing covenant ratios for a period up to and including the quarter ended September 30, 2019.

On August 11, 2017, we completed the sale of our Olds/Garrington assets for cash consideration of $300 million prior to closing adjustments.

On July 6, 2017, we completed the sale of a portion of our Swan Hills assets in North Central Alberta for total cash consideration of $185 million, prior to closing adjustments.

On June 2, 2017, we prepaid the remaining outstanding US$100 million of our 6.35% 2007 senior notes.

On May 16, 2017, we received notice from the NYSE that our Common Shares were no longer in compliance with one of the exchange's continued listing standards resulting from the average closing price of our common shares being less than US$1.00 per share over a consecutive 30 trading-day period. On November 1, 2017, we announced that we had received notification from the NYSE that we were back in compliance with the continued listing standards of the NYSE as of October 31, 2017.

On April 11, 2017, we completed the sale of our non-producing Montney lands at Bernadet in North East British Columbia for cash consideration of $92 million.

On April 3, 2017, we announced that we had prepaid US$300 million of our 6.35% 2007 senior notes.

On March 31, 2017, we redeemed all $126.6 million of our 6.25% series B convertible debentures on maturity, with cash on hand.

On February 9, 2017, we amended our Credit Facility to remove the Senior Debt to Total Capitalization covenant.

On February 8, 2017, Ms. Margaret L. Byl resigned from our Board for medical reasons.

On January 18, 2017, we announced our 2017 interim capital program and provided guidance on 2017 expected production and costs. Our 2017 interim capital budget reflected our plan to spend $125 million in 2017.

On January 6, 2017, we completed the sale of a 4% non-convertible gross overriding royalty on our Lindbergh assets and an interest in certain proprietary seismic for aggregate cash consideration of $250 million. The 4% overriding royalty would represent a 10.7% decrease (at a 10% discount rate) in the December 31, 2016 P+P net present value of Future Net Revenue for Lindbergh.

Financial Year ended December 31, 2016

On December 21, 2016, we amended our Term Notes to waive compliance at December 31, 2016, with the Total Debt to Total Capitalization covenant.

On October 6, 2016, we announced a 21% increase in our P+P reserves at our Lindbergh thermal project and a corresponding 63% increase in the value of our P+P reserves from $1.56 billion to $2.55 billion, compared to year end 2015.

On June 28, 2016, Messrs. John B. Zaozirny and Michael S. Parrett retired as directors of the Corporation. Mr. Kelvin B. Johnston was appointed Chairman of the Board to fill the vacancy created by Mr. Zaozirny's retirement.

On May 30, 2016, we announced that we had received approval under the EPEA for our 17,500 bbl/d second commercial phase of our Lindbergh thermal project.

On May 3, 2016, we reported our first quarter financial results and announced that we had received notification from the NYSE that we were back in compliance with the continued listing standards of the NYSE as of April 29, 2016.

On February 25, 2016, we announced the launch of a normal course issuer bid for up to 10% of our 6.25% series B convertible debentures. Through to December 31, 2016, the Corporation had repurchased and cancelled an aggregate of $10.2 million principal amount of the outstanding 6.25% series B convertible debentures at an aggregate cost of $9.2 million. This normal course issuer bid expired on February 28, 2017 with no additional repurchases in 2017.

On January 20, 2016, we announced our 2016 capital program and provided guidance on 2016 expected production and costs. Our 2016 capital budget reflected our plan to spend between $60 and $70 million in 2016. We also announced, at the same time, the suspension of our dividend until further notice.

SIGNIFICANT ACQUISITIONS DURING 2018

We did not complete any significant acquisitions during the most recently completed financial year for which disclosure is required under Part 8 of NI 51-102 Continuous Disclosure Obligations.

DESCRIPTION OF OUR BUSINESS

General

Pengrowth is a conventional resource developer of Canadian oil and natural gas assets. We are currently focused on growing bitumen production from the Lloydminster formation at our Lindbergh thermal oil project through steam assisted gravity drainage ("**SAGD**"). The project encompasses 32.5 sections of land with regulatory approval for 40,000 bbl/d. As one of the southernmost SAGD projects in Alberta, Lindbergh has natural advantages in terms of location and oil quality that allows flexibility in accessing markets.

Pengrowth's 100% owned Groundbirch property in the Montney fairway encompasses 19 sections of land. This project fulfills the Lindbergh project's natural gas needs. Dry natural gas from the Montney formation is produced using horizontal wells and multi-stage fracture technology with drilling potential of up to 360 unrisked net locations. The Corporation operates a 30 MMcf/d facility to process and deliver natural gas onto major pipelines.

Our long term goal is to maximize value creation for the benefit of our Shareholders. Our competitive position is dependent on our ability to execute our business strategy. A key factor affecting our finances is commodity prices over which we have no control.

Business Strategy

Our corporate strategy is to build a sustainable entity through the development of our large accumulations of bitumen and natural gas with their associated low declines and low cost structures.

Our operational focus is to progress with a measured development of our thermal project at Lindbergh. We continue to deploy horizontal well multi-stage fracturing technology at our natural gas property at Groundbirch. Both Lindbergh and Groundbirch provide significant future drilling and development opportunities with Lindbergh having the potential to produce 40,000 to 50,000 bbl/d of bitumen. See additional details on these properties under *"Operational Information – Principal Producing Properties"* below.

For 2019, we have established a $45 million capital spending level that is focused on adding production volumes from our two, core 100% owned assets at Lindbergh and Groundbirch. However, until Pengrowth refinances its term debt and renews its credit facility, capital spending will not exceed $21 million.

Specialized Skill and Knowledge

Conducting operations in the oil and natural gas industry require professionals with skills and knowledge in diverse fields of expertise. In the course of our exploration and production activities, we utilize the expertise of geophysicists, geologists and engineers. We face the challenge of attracting and retaining sufficient employees to meet our needs. See "*Risk Factors*".

Competitive Conditions

There is strong competition relating to all aspects of the oil and natural gas industry. We actively compete for capital, skilled personnel, undeveloped land, reserve acquisitions, access to equipment, processing facilities and pipeline and refining capacity, and in all other aspects of our operations, with a substantial number of other organizations, many of whom may have greater technical and financial resources than us. Some of those organizations not only explore for, develop, and produce oil and natural gas, but also carry-on refining operations and market petroleum and other products on a world-wide basis and, as such, have greater and more diverse resources on which to draw.

Our larger competitors may be able to better absorb the impact of changes to applicable laws and regulations and may be able to more easily handle longer periods of volatile oil and gas prices. Competitive conditions may be significantly affected by factors beyond our control, including international political stability, domestic political stability, overall levels of supply and demand for oil and gas, market prices for oil and natural gas and the markets for synthetic fuels and alternative energy sources.

Cyclical and Seasonal Factors

Our operational results and financial condition are highly dependent on the market price of oil and natural gas. Prices for these commodities have fluctuated widely during recent years and are determined by supply and demand factors, weather, general economic conditions and political environments, as well as conditions in other oil- and natural gas-producing regions. The prices for oil and natural gas are likely to continue to be volatile, and depressed or declining prices for these commodities could have an adverse effect on our financial condition and operations. We actively seek to mitigate such price risks through various risk management strategies including hedging the price of WTI as well as the use of fixed differential apportionment protected physical sales contracts.

The exploration and development of oil and natural gas reserves is dependent on access to areas where production is to be conducted. Access is affected by seasonal weather conditions, including freeze-up and break-up.

Health, Safety and Environmental Protection

We have rigorous health, safety and environmental protection policies aimed at ensuring that our operations are conducted in a safe and prudent manner. These policies also encompass our remediation, abandonment and site reclamation activities.

We believe that we meet all existing environmental standards and regulations and sufficient amounts are included in our capital expenditure budget to continue to meet current environmental protection requirements.

It is expected that we will incur abandonment and reclamation costs as existing oil and gas properties are abandoned. In 2018, expenditures for normal compliance with environmental regulations as well as expenditures for above-normal compliance were not material to the Corporation.

Code of Ethics

In addition to the health, safety and environmental protection policies, Pengrowth has adopted a code of ethics, as that term is defined in Form 40-F under the US Securities Exchange Act of 1934 (the “Code of Ethics”) that applies to Pengrowth's directors, officers, employees, consultants and independent contractors. Topics addressed in the Code of Ethics include conflicts of interest, fraud and corruption, confidential information and compliance with corporate policies, among other matters. All directors, officers, employees, consultants and contractors are required to review and accept the Code of Ethics annually.

During the year ended December 31, 2018, Pengrowth did not grant any waivers (including implicit waivers) from the Code of Ethics.

The Code of Ethics is available for viewing on our website www.pengrowth.com under the heading "Corporate Governance - Code of Business Conduct and Ethics", and is available in print to any Shareholder who requests it. Requests for copies of the Code of Ethics should be made by contacting: Investor Relations, Pengrowth Energy Corporation, Suite 1600, 222 - 3rd Avenue S.W., Calgary, Alberta, Canada, T2P 0B4.

Employees

As at December 31, 2018, we had 104 permanent employees.

Revenue Sources

For the year ended December 31, 2018, the sale of oil and natural gas accounted for 100% of revenue before royalties. For the year ended December 31, 2017, the sale of oil and natural gas accounted for 100% of revenue before royalties.

PRINCIPAL PRODUCING PROPERTIES AND OPERATIONS

The following table summarizes our principal producing properties as of December 31, 2018 based on the GLJ Report using forecast prices and costs. The following table utilizes data from the GLJ Report in respect of our oil and gas properties effective December 31, 2018. The table also contains our average daily production of oil, bitumen, natural gas, shale gas and NGL for the year ended December 31, 2018.

Summary of Company Interest at December 31, 2018[1]
(Forecast Prices and Costs)[2]

Field	P+P Reserves (Mboe[3])	Remaining Reserve Life (years)	P+P Reserve Life Index (years)	P+P Value Before Tax Discounted at 10%[4] ($MM)	2018 Oil Production (bbl/d)	2018 Bitumen Production (bbl/d)	2018 Gas Production (MMcf/d)	2018 Shale Gas Production (MMcf/d)	2018 NGL Production (bbl/d)	2018 Total Production (BOE/d[3])
Lindbergh	311,395	30	48	2,420	-	16,325	-	-	-	16,325
Groundbirch	131,971	50	118	322	-	-	-	17,458	-	2,910
Subtotal	**443,366**	**50**	**56**	**2,742**	**-**	**16,325**	**-**	**17,458**	**-**	**19,234**
Remainder[5]	3,202	-	-	18	675	-	11,258	-	239	2,790
Total	**446,568**	**50**	**56**	**2,760**	**675**	**16,325**	**11,258**	**17,458**	**239**	**22,025**

Notes:

(1) 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.

(2) Forecast prices are shown under the heading "Pricing Assumptions".

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

(4) Estimated Future Net Revenues disclosed do not represent fair market value.

(5) "Remainder" includes our Working Interests and Royalty Interests in 13 other properties of which reserves were assigned.

The following is a narrative description of our material oil and gas properties and operations as at December 31, 2018.

Lindbergh

The Lindbergh thermal property is located approximately 420km north east of Calgary, Alberta and 50km south of Bonnyville, Alberta. We have a 100% Working Interest in the Lindbergh oil sands leases, located in the Cold Lake oil sands district in northeastern Alberta and covering 20,800 net acres (32.5 sections). When discussing contingent resources for Lindbergh, we include our 100% owned Muriel Lake property located approximately 8km to the north east of the Lindbergh lease which is comprised of an additional 6,400 net acres (10 sections). The Corporation has drilled and evaluated 226 gross wells, including evaluation/observation wells, SAGD well pairs and infill wells since acquiring the Lindbergh area properties in 2004. Additionally, Pengrowth has 101 square kilometres of interpreted proprietary three dimensional seismic data covering our prospective properties.

The main bitumen resource at Lindbergh is located within the Lloydminster Formation of the Mannville Group, at an approximate depth of 500 metres. Oil gravity (quality) ranges from 9.5 - 11 °API. The average exploitable reservoir pay thickness is 19.2 metres in the 12,500 bbl/d first phase commercial project area. There appears to be no top water or top gas thief zones within the Lloydminster Formation in the project development area. A competent cap-rock is provided by the general petroleum shale, which is pervasive and consistent throughout the area.

The Lindbergh 12,500 bbl/d of bitumen design rate central processing facility ("**CPF**"), was constructed commencing in 2013, with first production in 2015. Production has consistently been above the design capacity of 12,500 bbl/d since start up. In May 2016, regulatory approval was received to increase the average annual production throughput to 30,000 bbl/d of bitumen and in August 2017 an EPEA scheme amendment was approved for expansion to 40,000 bbl/d of bitumen at Lindbergh. The Phase 1a expansion project was initiated in 2017 and was anticipated to increase produced bitumen rates to in excess of 18,000 bbl/d peak production by the end of 2018. Phase 1a included 10 new well pairs and 10 infill wells. In 2017, all 10 well pairs and two infill wells were drilled, with 7 of the 10 well pairs and the 2 infill wells being brought on stream, as well. Phase 1a was completed in 2018 with the remaining 3 well pairs being brought on stream, as well as, drilling 8 infill wells and bringing them on stream. As of December 31, 2018, the Phase 1a expansion was completed contributing to the December 31, 2018 produced bitumen exit rate of 19,120 bbl/d.

Over the life of the current Phase 1 commercial project, a total of 158 well pairs (including the 32 existing well pairs) and 35 infill wells (including 10 existing infill wells) are expected to be drilled from several pad sites within the project area, recovering Proved Reserves of 159 MMbbl of bitumen remaining as of December 31, 2018. The production life for each individual well pair is expected to be eight to nine years.

On June 26, 2018, Pengrowth announced its Multi-Year Development Plan which shifted its growth strategy from a large phase 2 build-out to a more incremental approach to make it possible to grow within cash flow. Pengrowth expects to grow production at Lindbergh to 35,000 bbl/d by 2023. To achieve this, Pengrowth will seek a third party to operate a co-generation facility at Lindbergh to provide both the electricity and steam required for growth. Low-cost proven technologies such as solvents and gases will also be deployed to enhance steam efficiency.

With expansion to 35,000 bbl/day of capacity, the project is expected to recover 311 MMbbl of Total Proved Plus Probable Reserves as of December 31, 2018, from a total of 266 well pairs, including the 32 existing well pairs, and 267 infill wells, including the 10 existing infill wells. Given the strong results to-date, additional productivity is thought to be possible and anticipated from the existing infrastructure and from future expansion opportunities.

As mentioned above under "General Development of the Business - Three Year History" , in January 2017, we sold a 4% non-convertible gross overriding royalty on our Lindbergh assets and an interest in certain proprietary seismic for aggregate cash consideration of $250 million.

For additional information, see "*Lindbergh Oil Sands Reserves and Contingent Resources*" in Appendix A to this AIF.

On December 13, 2016, the Corporation and Koch Oil Sands Operating ULC ("Koch") submitted an EPEA application to the AER with respect to the potential development of the Selina SAGD project located approximately 50km south east of Bonnyville, Alberta. The proposed project is designed for an annual average production rate of 12,500 bbl/d of bitumen. The Selina SAGD project is a 50/50 joint venture between the Corporation and Koch. Koch is the operator of this project as of the date of this AIF. Management has been advised that the AER approval process for these applications will take at least 24 months from the date of submission.

For additional information, see "*Selina Oil Sands Contingent Resources*" in Appendix A to this AIF.

Groundbirch

Our Groundbirch property is located approximately 40km south west of Fort St. John, British Columbia and covers an area of 12,536 gross/net acres. We have a 100% Working Interest in these lands. At Groundbirch, we currently have 22 producing wells producing approximately 24 MMcf/d of gas from the Montney formation, with little or no liquids.

The gas bearing Montney formation occurs at a vertical depth of approximately 2,200 metres and has a gross thickness of up to 230 metres. The Montney consists of thin, laminated interbedded sands, silts and shales and has very low permeability, in the order of one micro-Darcy. As a result of the very low permeability, the reservoir is developed with horizontal wells using multi-stage fracture technology.

During 2018, Pengrowth stimulated three of four horizontal Montney wells at Groundbirch that were drilled in 2017. The fourth well was partially stimulated in 2018 and the final stimulation of remaining stages was executed in January 2019. All four wells are landed in the Upper Montney zone. Two wells are landed in the U2 (mid-horizon in the Upper Montney) with 1,300 metre and 3,000 metre lateral lengths, respectively, and two are landed in the U3 (lower horizon in the Upper Montney), each with 1,300 metre lateral lengths. Gas plant sales gas pipeline tie-in to TransCanada Pipeline's ("**TCPL's**") NOVA Gas Transmission Ltd. System ("**NGTL system**") was completed in 2018 with sales gas volume flowing onto TCPL's NGTL system in Alberta.

With facility expansion to 60 MMcf/d of gas throughput, Groundbirch will be capable of meeting the fuel gas needs of our Lindbergh project through to 35,000 bbl/d of bitumen production.

For additional information, see "*Groundbirch Reserves and Contingent Resources*" in Appendix A to this AIF.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMAITON

Relevant Dates

This Statement of Reserves Data and Other Oil and Gas Information is dated February 27, 2019 with an effective date of December 31, 2018 unless indicated otherwise. Reserves evaluations have not been updated since the effective date and, thus, do not reflect changes in Pengrowth's reserves since that date. The preparation date of the information is January 15, 2019.

Disclosure of Reserves Data

The information in this section is based upon an evaluation by GLJ, prepared in accordance with NI 51-101, with an effective date of December 31, 2018 contained in the GLJ Report, with the exception of information relating to income tax and the after-tax Future Net Revenues associated with our reserves, which we determined. The effective date of the information in this section is December 31, 2018 and the preparation date is January 15, 2019 when the final information was provided. The information in this section summarizes our oil, liquids and natural gas reserves and the net present values of Future Net Revenue for these reserves using GLJ's forecast prices and costs and constant prices and costs. We engaged GLJ to provide an independent evaluation of Proved Reserves and Proved Plus Probable Reserves for all our properties. It is our practice to obtain an engineering report evaluating all of our Proved Reserves and Probable Reserves as at December 31 of each year. Only in respect of the Lindbergh oil sands property and the Groundbirch natural gas property did GLJ evaluate Possible Reserves and Contingent Resources. GLJ also evaluated Contingent Resources in our Selina oil sands property. The GLJ evaluation of Possible Reserves and Contingent Resources is discussed in Appendix A to this AIF. All of our reserves are in Canada in the provinces of Alberta, British Columbia, Saskatchewan and Nova Scotia. In certain instances in this AIF, we have presented estimates of reserves, Future Net Revenue and Contingent Resources for individual properties. The estimates of reserves, Future Net Revenue and Contingent Resources for individual properties may not reflect the same confidence level as estimates of reserves, Future Net Revenue and Contingent Resources for all properties, due to the effects of aggregation.

The following tables set forth certain information relating to our oil and natural gas reserves and the net present value of the estimated Future Net Revenue associated with such reserves as at December 31, 2018 contained in the GLJ Report. These tables summarize the data contained in the GLJ Report, and, as a result, may contain slightly different numbers than the GLJ Report due to rounding. Columns or rows may not add due to rounding.

Our Future Net Revenues associated with the production and reserves contained in this AIF reflect the royalty programs in-place on December 31, 2018.

The information set forth below is derived from the GLJ Report, which has been prepared in accordance with the standards contained in the Canadian Oil and Gas Evaluation ("**COGE**") Handbook and the reserves definitions contained in NI 51-101 and the COGE Handbook. The GLJ Report incorporates estimates of abandonment and reclamation costs for existing and future wells to which reserves have been assigned and for certain facilities. **The GLJ forecasts of Future Net Revenue are stated prior to any provision for income taxes, interest costs or general and administrative costs and after the deduction of estimated future capital expenditures for wells to which reserves have been assigned. The estimated Future Net Revenue shown below does not represent the fair market value of the properties. There is no assurance that such price and cost assumptions will be attained and variances could be material. The recovery and estimates of crude oil, NGL and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, NGL and natural gas reserves may be greater than or less than the estimates provided herein.**

We determined the Future Net Revenue and present value of Future Net Revenue after income taxes by utilizing GLJ's before income tax Future Net Revenue and our estimate of income tax. Our estimate of cash income tax makes use of the following assumptions:

- corporate income tax at the current legislated rate;
- annual general and administrative expenses at the current rate;
- interest expense at the current rate;
- tax pool deductions utilizing our existing $2.4 billion of tax pools and forecasted additions to our tax pools from capital expenditures as forecast by GLJ; and
- any such other additional deductions and adjustments as is and would be consistent with the manner in which we file and would file future tax returns.

The after-tax net present value of our oil and gas properties reflects the tax burden of our properties on a stand-alone basis. It does not provide an estimate of the value of us as a business entity, which may be significantly different.

The net revenues estimated in the GLJ Report represent estimates of the revenues from oil and gas sales from our petroleum and natural gas properties together with an estimate of processing revenues less royalties (net of incentives), mineral taxes, field operating expenses, certain abandonment and reclamation costs and capital obligations. These net revenues are not the same as cash flows from operating activities reported by the Corporation in our statement of cash flows. The GLJ Report does not estimate general and administrative expenses and interest.

In accordance with the requirements of NI 51-101, the Report on Reserves Data and Contingent Resources Data by Independent Qualified Reserves Evaluator or Auditor in Form 51-101F2 and the Report of Management and Directors on Oil and Gas Disclosure in Form 51-101F3 are attached to this AIF as Appendices B and C, respectively.

Reserves Data (Forecast Prices and Costs)

Summary of Oil and Gas Reserves as of December 31, 2018
(Forecast Prices and Costs)[1]

Reserves Category	Light Crude Oil and Medium Crude Oil		Heavy Crude Oil		Bitumen		Natural Gas Liquids	
	Company Gross (Mbbl)	Company Net (Mbbl)	Company Gross (Mbbl)	Company Net (Mbbl)	Company Gross (Mbbl)	Company Net (Mbbl)	Company Gross (Mbbl)	Company Net (Mbbl)
Proved Reserves								
Proved Developed Producing	561	502	-	-	19,609	17,903	10	8
Proved Developed Non-Producing	600	544	-	-	0	0	53	43
Proved Undeveloped	0	0	-	-	139,544	103,067	0	0
Total Proved Reserves	**1,161**	**1,046**	**-**	**-**	**159,153**	**120,970**	**63**	**51**
Probable Reserves	313	275	-	-	152,242	109,771	22	18
Total Proved Plus Probable Reserves	**1,474**	**1,321**	**-**	**-**	**311,395**	**230,741**	**86**	**69**

Reserves Category	Conventional Natural Gas		Shale Gas		Coal Bed Methane		Total Oil Equivalent Basis[2]	
	Company Gross (MMcf)	Company Net (MMcf)	Company Gross (MMcf)	Company Net (MMcf)	Company Gross (MMcf)	Company Net (MMcf)	Company Gross (Mboe)	Company Net (Mboe)
Proved Reserves								
Proved Developed Producing	1,049	951	39,497	37,119	1,717	1,628	27,224	25,030
Proved Developed Non-Producing	2,924	2,775	6,304	5,788	625	573	2,295	2,110
Proved Undeveloped	0	0	147,198	127,506	250	237	164,119	124,357
Total Proved Reserves	**3,972**	**3,726**	**192,998**	**170,413**	**2,592**	**2,437**	**193,638**	**151,496**
Probable Reserves	1,177	1,085	598,826	499,454	1,752	1,668	252,869	193,765
Total Proved Plus Probable Reserves	**5,149**	**4,812**	**791,824**	**669,867**	**4,344**	**4,105**	**446,508**	**345,261**

Notes:

(1) Forecast prices are shown under the heading "Pricing Assumptions".

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

Summary of Net Present Value of Future Net Revenue as of December 31, 2018
Before and After Income Taxes (Forecast Prices and Costs)[1]

	Before Income Taxes Discounted at (%/year) - $MM					Unit Value Before Income Tax Discounted at 10%/year[2] [3]	
Reserves Category	**0%**	**5%**	**10%**	**15%**	**20%**	**$/BOE**	**$/McfGE**
Proved Reserves							
Proved Developed Producing	498	457	422	391	364	16.85	2.81
Proved Developed Non-Producing	26	20	16	13	11	7.46	1.24
Proved Undeveloped	3,832	1,954	1,112	690	456	8.95	1.49
Total Proved Reserves	**4,356**	**2,431**	**1,550**	**1,094**	**832**	**10.23**	**1.71**
Probable Reserves	5,377	2,387	1,210	675	402	6.25	1.04
Total Proved Plus Probable Reserves	**9,734**	**4,819**	**2,760**	**1,769**	**1,234**	**7.99**	**1.33**

	After Income Taxes Discounted at (%/year)[4] - $MM				
Reserves Category	**0%**	**5%**	**10%**	**15%**	**20%**
Proved Reserves					
Proved Developed Producing	498	457	422	391	364
Proved Developed Non-Producing	26	20	16	13	11
Proved Undeveloped	3,084	1,688	1,004	639	429
Total Proved Reserves	**3,608**	**2,165**	**1,441**	**1,043**	**804**
Probable Reserves	3,576	1,770	940	532	316
Total Proved Plus Probable Reserves	**7,184**	**3,935**	**2,381**	**1,574**	**1,120**

Notes:

(1) Forecast prices are shown under the heading "Pricing Assumptions".

(2) Net present value of Future Net Revenue per reserve unit values are based on our net reserves.

(3) Natural gas has been converted to barrels of oil equivalent on the basis of six (6) Mcf of natural gas being equal to one barrel of oil. Oil and NGL have been converted to thousand cubic feet of natural gas equivalent on the basis of one barrel of oil or NGL being equal to six (6) Mcf of natural gas.

(4) After-tax values were calculated using current corporate tax rates, existing tax pools and additions to the tax pools through capital expenditures as forecast by GLJ. See "S*tatement of Reserves Data and Other Oil & Gas Information - Disclosure of Reserves Data"* for additional descriptions of the assumptions made in calculating the after-tax values.

Total Future Net Revenue (undiscounted) as of December 31, 2018
(Forecast Prices and Costs)[1] ($MM)

Reserves Category	Revenue	Royalties[2]	Operating Costs	Development Costs	Abandonment and Reclamation Costs[3]	Future Net Revenue Before Income Taxes	Income Tax	Future Net Revenue After Income Taxes
Total Proved	12,627	3,069	3,042	1,870	290	4,356	748	3,608
Total Proved Plus Probable	27,422	6,956	5,532	4,635	565	9,734	2,550	7,184

Notes:

(1) Forecast prices are shown under the heading "Pricing Assumptions".

(2) Crown royalties payable to the provinces of Alberta, British Columbia, Saskatchewan and Nova Scotia, freehold and over-riding royalties payable and other minor burdens.

(3) Includes GLJ's forecast of well abandonment and reclamation costs, abandonment of Sable Island facilities and subsea pipelines and abandonment and reclamation of the Lindbergh central processing facility, based on estimates by the Corporation, but does not include abandonment and surface reclamation costs for any other facilities. See "S*tatement of Reserves Data and Other Oil & Gas Information – Significant Factors or Uncertainties Affecting Reserves Data - Additional Information Concerning Abandonment & Reclamation Costs*".

Net Present Value of Future Net Revenue By Product Type as of December 31, 2018
(Forecast Prices and Costs)[1]

Reserves Category	Product Type	Future Net Revenue Before Income Taxes (discounted at 10%/year) ($MM)	Unit Value[4][5] ($/BOE)	Unit Value[4][5] ($/McfGE)
Total Proved	Light Crude Oil and Medium Crude Oil (including solution gas and other by-products)[2]	23	20.10	3.35
	Bitumen[2]	1,419	11.73	1.96
	Conventional Natural Gas (including by-products but excluding solution gas from oil wells)[3]	-4	-6.86	-1.14
	Shale Gas[3]	112	3.95	0.66
	Coal Bed Methane[3]	-1	-1.84	-0.31
	Total	**1,550**	**10.23**	**1.71**
Total Proved Plus Probable	Light Crude Oil and Medium Crude Oil (including solution gas and other by-products)[2]	27	18.57	3.10
	Bitumen [2]	2,363	10.24	1.71
	Conventional Natural Gas (including by-products but excluding solution gas from oil wells)[3]	-3	-4.62	-0.77
	Shale Gas[3]	373	3.34	0.56
	Coal Bed Methane[3]	0	-0.26	-0.04
	Total	**2,760**	**7.99**	**1.33**

Notes:

(1) Forecast prices are shown under the heading "Pricing Assumptions".

(2) Including solution gas and other by-products.

(3) Including by-products but excluding solution gas.

(4) Net present value of Future Net Revenue per BOE or McfGE are based on our net reserves.

(5) Natural gas has been converted to barrels of oil equivalent on the basis of six (6) Mcf of natural gas being equal to one barrel of oil. Oil and NGL have been converted to thousand cubic feet of natural gas equivalent on the basis of one barrel of oil or NGL being equal to six (6) Mcf of natural gas.

Reserves Data (Constant Prices and Costs)

Summary of Oil and Gas Reserves as of December 31, 2018
(Constant Prices and Costs)[(1)]

Reserves Category	Light Crude Oil and Medium Crude Oil Company Gross (Mbbl)	Light Crude Oil and Medium Crude Oil Company Net (Mbbl)	Heavy Crude Oil Company Gross (Mbbl)	Heavy Crude Oil Company Net (Mbbl)	Bitumen Company Gross (Mbbl)	Bitumen Company Net (Mbbl)	Natural Gas Liquids Company Gross (Mbbl)	Natural Gas Liquids Company Net (Mbbl)
Proved Reserves								
Proved Developed Producing	504	453	-	-	18,863	17,148	10	8
Proved Developed Non-Producing	424	382	-	-	—	—	10	8
Proved Undeveloped	—	—	-	-	138,715	119,521	—	—
Total Proved Reserves	**929**	**835**	**-**	**-**	**157,578**	**136,669**	**19**	**16**
Probable Reserves	353	313	-	-	153,589	129,000	5	4
Total Proved Plus Probable Reserves	**1,282**	**1,148**	**-**	**-**	**311,167**	**265,669**	**24**	**20**

Reserves Category	Conventional Natural Gas Company Gross (MMcf)	Conventional Natural Gas Company Net (MMcf)	Shale Gas Company Gross (MMcf)	Shale Gas Company Net (MMcf)	Coal Bed Methane Company Gross (MMcf)	Coal Bed Methane Company Net (MMcf)	Total Oil Equivalent Basis[(2)] Company Gross (Mboe)	Total Oil Equivalent Basis[(2)] Company Net (Mboe)
Proved Reserves								
Proved Developed Producing	1,039	947	31,303	30,364	415	397	24,837	22,893
Proved Developed Non-Producing	788	817	6,017	5,836	—	—	1,568	1,499
Proved Undeveloped	0	0	119,086	115,513	0	0	158,562	138,773
Total Proved Reserves	**1,826**	**1,764**	**156,405**	**151,713**	**415**	**397**	**184,967**	**163,165**
Probable Reserves	368	362	597,513	579,578	6	6	253,595	225,975
Total Proved Plus Probable Reserves	**2,195**	**2,126**	**753,919**	**731,292**	**421**	**402**	**438,562**	**389,141**

Notes:

(1) Constant prices are shown under the heading "Pricing Assumptions".

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

Summary of Net Present Value of Future Net Revenue as of December 31, 2018
Before and After Income Taxes (Constant Prices and Costs)[(1)]

Reserves Category	Before Income Taxes Discounted at (%/year) - $MM 0%	5%	10%	15%	20%	Unit Value Before Income Taxes Discounted at 10%/year[(2)(3)] $/BOE	$/McfGE
Proved Reserves							
Proved Developed Producing	272	266	257	247	236	11.24	1.87
Proved Developed Non-Producing	11	9	8	7	6	5.29	0.88
Proved Undeveloped	1,018	533	295	166	91	2.13	0.35
Total Proved Reserves	**1,300**	**809**	**560**	**420**	**334**	**3.43**	**0.57**
Probable Reserves	1,168	452	166	40	(19)	0.73	0.12
Total Proved Plus Probable Reserves	**2,468**	**1,261**	**726**	**460**	**315**	**1.87**	**0.31**

Reserves Category	After Income Taxes Discounted at (%/year)[(4)] - $MM 0%	5%	10%	15%	20%
Proved Reserves					
Proved Developed Producing	272	266	257	247	236
Proved Developed Non-Producing	11	9	8	7	6
Proved Undeveloped	1,018	533	295	166	91
Total Proved Reserves	**1,300**	**809**	**560**	**420**	**334**
Probable Reserves	873	367	136	26	(27)
Total Proved Plus Probable Reserves	**2,173**	**1,176**	**696**	**446**	**307**

Notes:

(1) Constant prices are shown under the heading "Pricing Assumptions".

(2) Net present value of Future Net Revenue per reserve unit values are based on our net reserves.

(3) Natural gas has been converted to barrels of oil equivalent on the basis of six (6) Mcf of natural gas being equal to one barrel of oil. Oil and NGL have been converted to thousand cubic feet of natural gas equivalent on the basis of one barrel of oil or NGL being equal to six (6) Mcf of natural gas.

(4) After-tax values were calculated using current corporate tax rates, existing tax pools and additions to the tax pools through capital expenditures as forecast by GLJ. See "*Statement of Reserves Data and Other Oil & Gas Information – Disclosure of Reserves Data*" for additional descriptions of the assumptions made in calculating the after-tax values.

Total Future Net Revenue (undiscounted) as of December 31, 2018
(Constant Prices and Costs)[1] ($MM)

Reserves Category	Revenue	Royalties[2]	Operating Costs	Development Costs	Abandonment and Reclamation Costs[3]	Future Net Revenue Before Income Taxes	Income Tax	Future Net Revenue After Income Taxes
Total Proved	5,624	705	1,920	1,486	213	1,300	0	1,300
Total Proved Plus Probable	11,628	1,544	3,513	3,726	376	2,468	295	2,173

Notes:

(1) Constant prices are shown under the heading "Pricing Assumptions".

(2) Crown royalties payable to the provinces of Alberta, British Columbia, Saskatchewan and Nova Scotia, freehold and over-riding royalties payable and other minor burdens.

(3) Includes GLJ's forecast of well abandonment and reclamation costs, abandonment of Sable Island facilities and subsea pipelines, and abandonment and reclamation of the Lindbergh central processing facilities, based on estimates by the Corporation, but does not include abandonment and surface reclamation costs for any other facilities. See "S*tatement of Reserves Data and Other Oil & Gas Information – Significant Factors or Uncertainties Affecting Reserves Data - Additional Information Concerning Abandonment & Reclamation Costs*".

Net Present Value of Future Net Revenue By Product Type as of December 31, 2018
(Constant Prices and Costs)[1]

Reserves Category	Product Type	Future Net Revenue Before Income Taxes (discounted at 10%/year) ($MM)	Unit Value[4][5] ($/BOE)	Unit Value[4][5] ($/McfGE)
Total Proved	Light Crude Oil and Medium Crude Oil (including solution gas and other by-products)[2]	16	17.14	2.86
	Bitumen[2]	546	4.00	0.67
	Conventional Natural Gas (including by-products but excluding solution gas from oil wells)[3]	-5	-22.33	-3.72
	Shale Gas[3]	5	0.18	0.03
	Coal Bed Methane[3]	-2	-27.93	-4.65
	Total	**560**	**3.43**	**0.57**
Total Proved Plus Probable	Light Crude Oil and Medium Crude Oil (including solution gas and other by-products)[2]	19	14.68	2.45
	Bitumen [2]	690	2.60	0.43
	Conventional Natural Gas (including by-products but excluding solution gas from oil wells)[3]	-5	-18.25	-3.04
	Shale Gas[3]	24	0.19	0.03
	Coal Bed Methane[3]	-2	-26.04	-4.34
	Total	**726**	**1.87**	**0.31**

Notes:

(1) Constant prices are shown under the heading "Pricing Assumptions".

(2) Including solution gas and other by-products.

(3) Including by-products but excluding solution gas.

(4) Net present value of Future Net Revenue per BOE or McfGE are based on our net reserves.

(5) Natural gas has been converted to barrels of oil equivalent on the basis of six (6) Mcf of natural gas being equal to one barrel of oil. Oil and NGL have been converted to thousand cubic feet of natural gas equivalent on the basis of one barrel of oil or NGL being equal to six (6) Mcf of natural gas.

Pricing Assumptions

Forecast Prices used in Estimates

The forecast price and cost assumptions assume the continuance of current laws and regulations and changes in wellhead selling prices, and take into account forecasted 2% annual inflation with respect to future operating and capital costs. The forecast prices are provided in the table below and reflect GLJ's January 1, 2019 price forecast as referred to in the GLJ Report. For historical prices realized during 2018, see "Production History (Netback)" in this AIF.

	Oil						Natural Gas	Natural Gas Liquids[1]				
Year	WTI Cushing Oklahoma (US$/bbl)	Edmonton Par Price 40° API (Cdn$/bbl)	Cromer Medium 29° API (Cdn$/bbl)	WCS Stream Quality (Cdn$/bbl)	Hardisty Heavy 12° API (Cdn$/bbl)	Lindbergh Bitumen Wellhead Calculated[4] (Cdn$/bbl)	AECO Gas Price (Cdn$/MMBtu)	Propane (Cdn$/bbl)	Butane (Cdn$/bbl)	Pentanes Plus (Cdn$/bbl)	Inflation Rates[2] (%/year)	Exchange Rate[3] (US$/Cdn$)
2019	56.25	63.33	58.90	47.67	37.65	48.71	1.85	25.33	21.45	67.67	0.0	0.7500
2020	63.00	75.32	70.05	58.44	51.21	51.04	2.29	32.39	37.66	79.22	2.0	0.7700
2021	67.00	79.75	74.16	65.82	59.51	55.05	2.67	36.68	47.85	83.54	2.0	0.7900
2022	70.00	81.48	75.78	67.90	61.62	56.78	2.90	39.11	57.04	85.49	2.0	0.8100
2023	72.50	83.54	77.69	70.12	63.82	59.08	3.14	41.77	58.48	87.80	2.0	0.8200
2024	75.00	86.06	80.04	72.73	66.45	61.32	3.23	43.03	60.24	90.30	2.0	0.8250
2025	77.50	89.09	82.85	75.76	69.48	64.33	3.34	44.55	62.36	93.33	2.0	0.8250
2026	80.41	92.62	86.13	79.28	73.01	67.35	3.41	46.31	64.83	96.86	2.0	0.8250
2027	82.02	94.57	87.95	81.24	74.96	70.45	3.48	47.28	66.20	98.81	2.0	0.8250
2028	83.66	96.56	89.80	83.22	76.95	71.86	3.54	48.28	67.59	100.80	2.0	0.8250
thereafter	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	2.0	0.8250

Notes:

(1) FOB Edmonton.

(2) Inflation rates for forecasting prices and costs.

(3) The exchange rates used to generate the benchmark reference prices in this table.

(4) Lindbergh forecast wellhead prices are calculated accounting for all diluent/blending and transportation costs.

Constant Prices used in Estimates

The constant price assumptions assume the continuance of current laws, regulations and operating costs in effect on the date of the GLJ Report. Product prices were determined from the actual prices on the first day of each month during 2018 and were not escalated. In addition to the product prices, operating and capital costs have no inflationary increase. The constant prices are as follows:

	Oil						Natural Gas	Natural Gas Liquids[1]				
Year	WTI Cushing Oklahoma (US$/bbl)	Edmonton Par Price 40° API (Cdn$/bbl)	Cromer Medium 29° API (Cdn$/bbl)	WCS Stream Quality (Cdn$/bbl)	Hardisty Heavy 12° API (Cdn$/bbl)	Lindbergh Bitumen Wellhead Calculated[2] (Cdn$/bbl)	AECO Gas Price (Cdn$/MMBtu)	Propane (Cdn$/bbl)	Butane (Cdn$/bbl)	Pentanes Plus (Cdn$/bbl)	Inflation Rate (%/year)	Exchange Rate (US$/Cdn$)
2019 and thereafter	65.56	70.07	70.42	50.44	40.76	33.80	1.46	27.77	33.82	79.39	0.0	0.7754

Notes:

(1) FOB Edmonton.

(2) Lindbergh constant wellhead price is calculated accounting for all diluent/blending and transportation costs.

Reserves Reconciliation

The following tables provide a reconciliation of our gross reserves of crude oil, bitumen, natural gas and NGL for the year ended December 31, 2018 presented using forecast prices and costs. All reserves are located in Canada.

Gross Reserves Reconciliation By Principal Product Type
(Forecast Prices and Costs)

	Light Crude Oil and Medium Crude Oil			Heavy Crude Oil			Bitumen			Natural Gas Liquids		
	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)
December 31, 2017	**2,037**	**672**	**2,709**	**-**	**-**	**-**	**163,334**	**153,724**	**317,057**	**141**	**29**	**170**
Discoveries	0	0	0	-	-	-	0	0	0	0	0	0
Extensions[1]	—	—	—				—	—	—	—	—	—
Infill Drilling[1]	—	—	—	-	-	-	—	—	—	—	—	—
Improved Recovery[1]	—	—	—	-	-	-	—	—	—	—	—	—
Technical Revisions	(46)	(154)	(201)	-	-	-	1,242	(946)	296	15	(5)	10
Acquisitions	11	3	14	-	-	-	—	—	—	—	—	—
Dispositions	(612)	(215)	(827)	-	-	-	—	—	—	(6)	(2)	(8)
Economic Factors	15	7	22	-	-	-	536	(536)	—	—	—	—
Production	(244)	—	(244)	-	-	-	(5,958)	—	(5,958)	(86)	—	(86)
December 31, 2018	**1,161**	**313**	**1,474**	**-**	**-**	**-**	**159,153**	**152,242**	**311,395**	**63**	**22**	**86**

	Conventional Natural Gas			Shale Gas			Coal Bed Methane			Total Oil Equivalent Basis[2]		
	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)	Proved (Mboe)	Probable (Mboe)	Proved Plus Probable (Mboe)
December 31, 2017	**6,689**	**1,262**	**7,951**	**152,847**	**593,606**	**746,452**	**3,404**	**1,943**	**5,348**	**192,668**	**253,894**	**446,561**
Discoveries	0	0	0	0	0	0	0	0	0	0	0	0
Extensions[1]	—	—	—	36,665	12,625	49,289	—	—	—	6,111	2,104	8,215
Infill Drilling[1]	—	—	—	—	—	—	—	—	—	—	—	—
Improved Recovery[1]	—	—	—	—	—	—	—	—	—	—	—	—
Technical Revisions	1,345	82	1,427	9,859	(6,676)	3,182	48	(167)	(119)	3,085	(2,232)	854
Acquisitions	—	—	—	—	—	—	—	—	—	11	3	14
Dispositions	(416)	(154)	(570)	—	—	—	—	—	—	(687)	(243)	(929)
Economic Factors	7	(13)	(5)	—	(728)	(728)	(451)	(25)	(475)	478	(657)	(180)
Production	(3,653)	—	(3,653)	(6,372)	0	(6,372)	(409)	—	(409)	(8,027)	—	(8,027)
December 31, 2018	**3,972**	**1,177**	**5,149**	**192,998**	**598,826**	**791,824**	**2,592**	**1,752**	**4,344**	**193,638**	**252,869**	**446,508**

Notes:

(1) These change categories correspond to standards set out in the Canadian Oil and Gas Evaluation Handbook. For reporting under NI 51-101, the aggregate reserves additions under Infill Drilling, Improved Recovery and Extensions should be considered in aggregate as "Extensions and Improved Recovery".

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

At December 31, 2018, Company Interest Total Proved Plus Probable Reserves at forecast prices and costs were 446.6 MMboe as compared to 446.6 MMboe reported at year end 2017. The following additional GLJ reserves reconciliation is presented for year end December 31, 2018.

Company Interest Reserves Reconciliation on Total Oil Equivalent Basis – Mboe[1]
(Forecast Prices and Costs)

	Total Proved Developed Producing Reserves	Total Proved Reserves	Total Proved Plus Probable Reserve
December 31, 2017	**33,257**	**192,718**	**446,632**
Technical [2]	(605)	3,548	653
Drilling Extensions	2,312	6,111	8,215
Infill Drilling	955	—	—
Acquisition	11	11	14
Sold	(669)	(677)	(919)
Production	(8,027)	(8,027)	(8,027)
December 31, 2018	**27,234**	**193,684**	**446,568**

Note:

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

(2) Technical reserves include changes due to economic factors

Significant factors bearing on the reserves reconciliation were as follows:

- Net reserve changes from drilling activity, improved recovery, technical revisions and economic factors replaced 120% and 110% of 2018 production for Proved Reserves and Total Proved Plus Probable Reserves, respectively.
- New reserve additions for development activity during 2018 amounted to 6.1 MMboe of Proved Reserves and 8.2 MMboe of Proved Plus Probable Reserves. The most significant addition occurred at Groundbirch where reserves were added in both Proved Reserves and Proved Plus Probable Reserves due to wells drilled in late 2017.
- Technical revisions resulted in a net increase of 3.5 MMboe of Proved Reserves and 0.7 MMboe of Total Proved Plus Probable Reserves. This was primarily due to improved economics at Lindbergh due to increased price forecast on oil, and improved development efficiencies at Groundbirch due to drilling longer laterals.

  Note: All reserves discussed above relate to Company Interest reserves.

ADDITIONAL INFORMATION RELATING TO RESERVES DATA

Undeveloped Reserves

Undeveloped Reserves are those reserves expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production.

Proved Undeveloped Reserves and Probable Undeveloped Reserves have been estimated in accordance with procedures and standards contained in the COGE Handbook. In general, Undeveloped Reserves are scheduled to be developed within the next two to five years. Much of the remaining capital scheduled beyond this period is for staged developments such as the Lindbergh thermal project and Groundbirch Montney gas development.

Company Gross Reserves First Attributed by Year[1]

Proved Undeveloped Reserves	Light Crude Oil and Medium Crude Oil (Mbbl)		Heavy Crude Oil (Mbbl)		Bitumen (Mbbl)		Natural Gas Liquids (Mbbl)		Conventional Natural Gas (MMcf)		Shale Gas (MMcf)		Coal Bed Methane (MMcf)		Total Oil Equivalent (Mboe)[2]	
	First Attributed	Total at year end	First Attributed	Total at year end	First Attributed	Total at year end	First Attributed	Total at year end	First Attributed	Total at year end	First Attributed	Total at year end	First Attributed	Total at year end	First Attributed	Total at year end
2016	345	5,232	-	-	45,978	130,007	2,920	4,760	23,826	43,240	-	86,677	-	5,093	53,214	162,500
2017	3	6	-	-	5,053	138,600	2	2	-	-	31,525	121,493	-	258	10,312	158,900
2018	-	-	-	-	-	139,544	-	-	-	-	26,675	147,198	-	250	4,446	164,119

Probable Undeveloped Reserves	Light Crude Oil and Medium Crude Oil (Mbbl)		Heavy Crude Oil (Mbbl)		Bitumen (Mbbl)		Natural Gas Liquids (Mbbl)		Conventional Natural Gas (MMcf)		Shale Gas (MMcf)		Coal Bed Methane (MMcf)		Total Oil Equivalent (Mboe)[2]	
	First Attributed	Total at year end	First Attributed	Total at year end	First Attributed	Total at year end	First Attributed	Total at year end	First Attributed	Total at year end	First Attributed	Total at year end	First Attributed	Total at year end	First Attributed	Total at year end
2016	581	5,245	-	-	9,000	166,850	2,522	5,405	22,345	57,020	13,230	574,818	-	5,039	18,032	283,646
2017	1	1	-	-	-	146,854	1	1	-	-	-	584,005	-	1,128	2	244,378
2018	-	-	-	-	-	144,792	-	-	-	-	24,071	581,956	-	1,093	4,012	241,967

Notes:

(1) "First Attributed" refers to reserves first attributed at year end of the corresponding fiscal year.

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

Proved Undeveloped Reserves

Proved Undeveloped Reserves comprise approximately 85% of Company Interest Proved Reserves on a BOE basis. Company Interest Proved Undeveloped Reserves of 164.1 MMboe were assigned by GLJ in accordance with NI 51-101. In general, Proved Undeveloped Reserves were assigned to certain properties because we intend to make the necessary capital commitments to convert the Undeveloped Reserves to Proved Developed Producing Reserves in the next few years. Proved Undeveloped Reserves have been primarily assigned for future oil sands development and development drilling.

The Lindbergh thermal project which came on stream in 2015 accounts for 85% of our Proved Undeveloped Reserves. SAGD well pairs and infill wells are forecast to be drilled until 2046. The pace of development is currently limited by the production and steam capacity of the existing central processing facility for the Phase 1 commercial project. It is the Company's intent to develop Lindbergh Proved Undeveloped Reserves by drilling well pairs and infill wells to continually maximize the central processing facility to 20,000 bbl/d bitumen or approximately 52,000 bbl/d steam.

The Groundbirch Montney gas property amounts to approximately 15% of our Proved Undeveloped Reserves. Drilling is forecast by GLJ to occur over the next five years to develop these reserves. It is the Company's intent to develop Groundbirch Proved Undeveloped Reserves by maximizing the current plant capacity of 30 MMCF/d in the short term, and then as commodity prices improve, expand the gas plant to 60 MMCF/d and continue to develop Proved Undeveloped Reserves to fill the capacity. The main gathering pipeline has been designed to handle 120 MMCF/d in consideration of future development.

Probable Undeveloped Reserves

Probable Undeveloped Reserves were assigned by GLJ in accordance with the requirements and standards of NI 51-101 and the COGE Handbook. Company Interest Probable Undeveloped Reserves amount to 242.0 MMboe and represent about 54.4% of the Total Proved Plus Probable Reserves. Probable Undeveloped Reserves are assigned for similar reasons and generally to the same properties as Proved Undeveloped Reserves, but also meet the requirements of the reserve classification to which they belong. Our largest Probable Undeveloped Reserves are distributed among certain properties as a percent of the total as follows: Lindbergh (60%) and Groundbirch (40%).

As outlined above, the Lindbergh thermal project accounts for 60% of our Proved Undeveloped Reserves. SAGD well pairs and infill wells are forecast to be drilled until 2046. It is the Company's intent to develop Lindbergh Proved Plus Probable Undeveloped Reserves by expanding the central processing facility in two increments of 7,500 bbl/d bitumen (19,700 bbl/d steam). The Company has plans to have these expansions occur in 2021 and 2025 respectively, pending commodity price improvement. By the end of 2025, the total facility capacity will be 35,000 bbl/d bitumen with 95,000 bbl/d of steaming capacity. The Undeveloped Proved Plus Probable Reserves will be developed by drilling well pairs and infill wells to continually maximize the central processing facility.

The Groundbirch Montney gas property accounts for 40% of our Probable Undeveloped Reserves. Drilling is forecast by GLJ to occur over the next five to ten years to develop these reserves. It is the Company's intent to develop the Groundbirch Proved Plus Probable Undeveloped Reserves by expanding the gas plant in 2020 to 60 MMCF/d, followed by an expansion to 120 MMCF/d in 2023, assuming strong commodity pricing. It is the Company's intent to develop the Proved Plus Probable Reserves by drilling wells to continually maximize the plant capacity thereafter.

SIGNIFICANT FACTORS OR UNCERTAINTIES AFFECTING RESERVES DATA

Additional Information Concerning Abandonment & Reclamation Costs

The total future abandonment and reclamation costs are based on management's estimate of costs to abandon, remediate and reclaim all wells and facilities having regard to our Working Interest and the estimated timing of the costs to be incurred in future periods and are referred to herein as the Corporation's asset retirement obligations. We have developed a process to calculate these estimates, which considers applicable regulations, actual and anticipated costs, type and size of the well or facility and the geographic location. These costs relate to wells and facilities in properties that may or may not have reserves attributed to them.

GLJ's forecast of well abandonment and reclamation costs for all wells with reserves assigned, abandonment costs for all Sable Island offshore and onshore facilities and pipelines upstream of the plant gate and abandonment and reclamation costs for the Lindbergh central processing facilities, based on estimates provided by the Corporation, are included in their report and therefore in their estimate of Future Net Revenue. All other abandonment and reclamation costs are not reflected in GLJ's estimate of Future Net Revenue.

We have estimated the net present value (discounted at 10% per annum) of our total asset retirement obligations, which are inclusive of those costs estimated by GLJ, to be approximately $99 million as at December 31, 2018, based on a total future liability (inflated at 1.5% per annum). Undiscounted and uninflated, the asset retirement obligations are estimated at approximately $405 million. 50% of these costs are expected to be incurred after 2056.

The following table summarizes our total current asset retirement obligations as at December 31, 2018:

Asset Retirement Obligations

	2019	2020	2021	Remainder	Total
Total Abandonment, Reclamation, Remediation & Dismantling ($MM)	31	50	15	309	405
Discounted at 10% ($MM)	28	41	11	19	99

The above table excludes asset retirement obligations associated with future development and, in particular, the development associated with Proved Developed Non-Producing, Proved Undeveloped and Probable Undeveloped Reserves, except where such activity would be coincidental with existing operations. GLJ's Proved Developed Producing reserve evaluation at forecast prices and costs is the best comparison to our current operation and includes $156 million ($101 million when discounted at 10%) of the current asset retirement obligations in the above table. Elsewhere, where we describe Future Net Revenue, only the GLJ forecast of abandonment obligation is included in the values.

FUTURE DEVELOPMENT COSTS

The following table outlines development costs deducted in the estimation of Future Net Revenue calculated utilizing both constant and forecast prices and costs, undiscounted and using a discount rate of 10% per annum for the years indicated. All of such development costs are estimated to be incurred in Canada.

Future Development Costs ($MM)

							Total	
Reserve Category	**2019**	**2020**	**2021**	**2022**	**2023**	**Remainder**	**Undiscounted**	**Discounted at 10%**
Proved Reserves (Constant Prices and Costs)	48	190	124	56	105	963	1,486	685
Proved Reserves (Forecast Prices and Costs)	48	194	135	81	114	1,299	1,870	793
Proved & Probable Reserves (Forecast Prices and Costs)	48	258	330	223	193	3,584	4,635	1,841

There are no reserves that are expected to be limited in their recovery due to their cost of development.

Finding and Development Costs

During 2018, we spent $64.7 million on development, maintenance and optimization, which added 6.1 MMboe of Proved Reserves and 8.2 MMboe of Proved Plus Probable Reserves, excluding revisions. Incorporating the net positive revisions resulted in an overall change of 9.7 MMboe of Proved Reserves and 8.9 MMboe of Total Proved Plus Probable Reserves. The development and optimization expenditures exclude $0.3 million in corporate expenditures for information technology projects and equipment inventory. The largest reserve additions were for reserves additions at Groundbirch offsetting 2017 activity and for infill wells drilled at Lindbergh.

Finding and Developments Costs are not necessarily calculated in the same manner by all issuers. Accordingly, they should not be used to make comparisons amongst different issuers.

Acquisitions and Divestitures

During 2018, the Corporation engaged in minor asset divestiture activity with net proceeds of $0.4MM.

Future Development Costs

The calculation of F&D Costs include changes in forecasted FDC relating to the reserves. These forecasts of FDC will change with time due to ongoing development activity, inflationary changes or reduction in capital costs and acquisition or disposition of assets. We provide the calculation of FD&A Costs both with and without change in FDC. We include FD&A Costs because we believe that acquisitions and dispositions can have a significant impact on our ongoing reserve replacement costs.

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

Proved Reserves	2018	2017	2016	2016-2018 Total/Weighted Average
Costs Excluding Future Development Costs				
Exploration and Development Capital Expenditures - $MM	64.7	117.4	64.2	246.3
Exploration and Development Reserve Additions including Revisions - MMboe	9.7	27.7	60.7	98.0
Finding and Development Cost - $/BOE	**6.70**	**4.24**	**1.06**	**2.51**
Net Acquisition (Disposition) Capital - $MM	(0.4)	(986.7)	(58.9)	(1,046.0)
Net Acquisition (Disposition) Reserve Additions - MMboe	(0.7)	(106.0)	(6.1)	(112.8)
Net Acquisition Cost - $/BOE	**0.62**	**9.31**	**9.66**	**9.28**
Total Capital Expenditures including Net Acquisitions (Dispositions) - $MM	64.3	(869.3)	5.3	(799.7)
Reserve Additions including Net Acquisitions (Dispositions) - MMboe	9.0	(78.3)	54.6	(14.7)
Finding, Development and Acquisition Cost - $/BOE	**7.14**	**11.10**	**0.10**	**54.29**
Costs Including Future Development Costs				
Exploration and Development Capital Expenditures - $MM	64.7	117.4	64.2	246.3
Exploration and Development Change in FDC - $MM	(61.8)	261.5	423.6	623.3
Exploration and Development Capital including Change in FDC - $MM	3.0	378.8	487.8	869.6
Exploration and Development Reserve Additions including Revisions - MMboe	9.7	27.7	60.7	98.0
Finding and Development Cost - $/BOE	**0.31**	**13.69**	**8.04**	**8.87**
Net Acquisition (Disposition) Capital - $MM	(0.4)	(986.7)	(58.9)	(1,046.0)
Net Acquisition (Disposition) FDC - $MM	(0.5)	(309.2)	(40.6)	(350.3)
Net Acquisition (Disposition) Capital including FDC - $MM	(0.9)	(1,295.9)	(99.5)	(1,396.3)
Net Acquisition (Disposition) Reserve Additions - MMboe	(0.7)	(106.0)	(6.1)	(112.8)
Net Acquisition Cost - $/BOE	**1.30**	**12.23**	**16.31**	**12.38**
Total Capital Expenditures including Net Acquisitions (Dispositions) - $MM	64.3	(869.3)	5.3	(799.7)
Total Change in FDC - $MM	(61.3)	(47.7)	383.0	274.0
Total Capital including Change in FDC - $MM	3.0	(917.1)	388.3	(525.8)
Reserve Additions including Net Acquisitions (Dispositions) - MMboe	9.0	(78.3)	54.6	(14.7)
Finding, Development and Acquisition Cost including FDC - $/BOE	**0.33**	**11.71**	**7.11**	**35.69**

Total Proved Plus Probable Reserves	2018	2017	2016	2016-2018 Total/Weighted Average
Costs Excluding Future Development Costs				
Exploration and Development Capital Expenditures - $MM	64.7	117.4	64.2	246.3
Exploration and Development Reserve Additions including Revisions - MMboe	8.9	3.0	76.2	88.0
Finding and Development Cost - $/BOE(1)	**7.30**	**39.49**	**0.84**	**2.80**
Net Acquisition (Disposition) Capital - $MM	(0.4)	(986.7)	(58.9)	(1,046.0)
Net Acquisition (Disposition) Reserve Additions - MMboe	(0.9)	(150.1)	(15.9)	(166.9)
Net Acquisition Cost - $/BOE	**0.45**	**6.57**	**3.70**	**6.27**
Total Capital Expenditures including Net Acquisitions (Dispositions) - $MM	64.3	(869.3)	5.3	(799.7)
Reserve Additions including Net Acquisitions (Dispositions) - MMboe	8.0	(147.2)	60.3	(78.9)
Finding, Development and Acquisition Cost - $/BOE	**8.08**	**5.91**	**0.09**	**10.14**
Costs Including Future Development Costs				
Exploration and Development Capital Expenditures - $MM	64.7	117.4	64.2	246.3
Exploration and Development Change in FDC - $MM	(306.8)	163.1	193.7	50.0
Exploration and Development Capital including Change in FDC - $MM	(242.1)	280.5	257.9	296.3
Exploration and Development Reserve Additions including Revisions - MMboe	8.9	3.0	76.2	88.0
Finding and Development Cost - $/BOE(2)	**(27.29)**	**94.36**	**3.38**	**3.37**
Net Acquisition (Disposition) Capital - $MM	(0.4)	(986.7)	(58.9)	(1,046.0)
Net Acquisition (Disposition) FDC - $MM	(0.5)	(455.8)	(124.7)	(581.0)
Net Acquisition (Disposition) Capital including FDC - $MM	(0.9)	(1,442.5)	(183.6)	(1,627.0)
Net Acquisition (Disposition) Reserve Additions - MMboe	(0.9)	(150.1)	(15.9)	(166.9)
Net Acquisition Cost - $/BOE	**0.96**	**9.61**	**11.55**	**9.75**
Total Capital Expenditures including Net Acquisitions (Dispositions) - $MM	64.3	(869.3)	5.3	(799.7)
Total Change in FDC - $MM	(306.3)	(292.7)	69.0	(530.0)
Total Capital including Change in FDC - $MM	(242.0)	(1,162.0)	74.3	(1,329.7)
Reserve Additions including Net Acquisitions (Dispositions) – MMboe	8.0	(147.2)	60.3	(78.9)
Finding Development and Acquisition Cost including FDC - $/BOE	**(30.39)**	**7.90**	**1.23**	**16.85**

Notes:

(1) The high F&D Cost excluding FDC for 2017 P+P Reserves is largely due to the 2017 capital activity focusing on promoting existing Probable Reserves to Proved Reserves combined with minor reserves adds.

(2) The high F&D Cost including FDC for 2017 is due to increased estimated FDC. The negative F&D cost including FDC for 2018 is due to decreased estimated FDC.

The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year.

RECYCLE RATIO

We calculate the Recycle Ratio to measure our performance. It reflects the amount of cash flow relative to investment. To calculate the Recycle Ratio, we divide annual operating netback by annual F&D Costs including change in FDC. Recycle ratios are not necessarily calculated in the same manner by all issuers. Accordingly, they should not be used to make comparisons amongst different issuers.

	2018	2017	2016	2016-2018 Weighted Average[4]
Operating Netback (after risk management), $/BOE[1]	13.47	13.23	28.62	20.62
Total Proved Reserves				
Proved F&D, $/BOE[2]	0.31	13.69	8.04	8.87
Proved Recycle Ratio	43.89	0.99	3.59	2.32
Total Proved Plus Probable Reserves				
P+P F&D, $/BOE[2][3]	-27.29	94.36	3.38	3.37
P+P Recycle Ratio	-0.49	0.14	8.53	6.13

Notes:

(1) Operating netback is calculated as shown in "Production History (Netback)".

(2) F&D uses Exploration and Development capital including change in FDC divided by Exploration and Development Reserve Additions including Revisions as shown above.

(3) The high F&D Cost including FDC for 2017 is due to increased estimated FDC. The negative F&D cost including FDC for 2018 is due to decreased estimated FDC.

(4) The three year weighted average is a better indicator of reserve replacement and Recycle Ratio performance given the timing difference between when reserves are booked and when capital is spent to develop them.

RESERVE LIFE INDEX

The Reserve Life Index ("**RLI**") provides a comparative measure of the longevity of the resources. We calculate the RLI by dividing 2018 Company Interest year end reserves by GLJ's 2018 forecasted production. RLIs are not necessarily comparative between different issuers as there is some variation in calculation methodology.

	Proved Producing Reserves	Total Proved Reserves	Total Proved Plus Probable Reserves
RLI, years	3.6	24.4	55.6
Reserves, MMboe[1][2]	27.2	193.7	446.6
2019 Forecast Production, BOE/d[1]	20,957	21,705	22,009

Notes:

(1) Both reserves and production are Company Interest.

(2) Reserves are calculated using Forecast Prices and Costs.

RESERVE REPLACEMENT

We provide reserve replacement data as an indication of the effectiveness of our investments made and the relative impact of that investment. The reserve replacement figures are calculated with and without net acquisitions included by dividing reserve additions by the current year's production. Reserve replacement figures should not be relied upon as being predictive of future performance or reserve growth or recoveries. Different issuers may calculate reserve replacement in different manners. Accordingly, reserve replacement ratios should not be treated as being standardized or comparable.

	2018	2017	2016	Weighted Average/Total 2016-2018
Without Net Acquisitions Proved Plus Probable Replacement (%)	110	20	365	201
P+P Additions plus Revisions, MMboe[1]	8.9	3.0	76.2	88.0
With Net Acquisitions Proved Plus Probable Replacement (%)	99	(994)	289	(180)
P+P Additions, Revisions plus net Acquisitions, MMboe[1]	8	(147.2)	60.3	(78.9)
Without Net Acquisitions Total Proved Replacement (%)	120	187	290	224
Total Proved Additions plus Revisions, MMboe[1]	9.7	27.7	60.7	98.0
With Net Acquisitions Total Proved Replacement (%)	112	(529)	261	(34)
Total Proved Additions, Revisions plus net Acquisitions, MMboe[1]	9.0	(78.3)	54.6	(14.7)
Current Year Production, MMboe[1]	8.0	14.8	20.9	43.7

Note:

(1) Both reserves and production are Company Interest.

OTHER OIL AND GAS INFORMATION

Oil and Gas Properties and Wells

As at December 31, 2018, we had an interest in 420 gross (269 net) producing oil and natural gas wells and 917 gross (586 net) non-producing wells. All wells are onshore except for wells in Nova Scotia which are all offshore.

	Producing		Non-Producing		Total	
	Gross	Net	Gross	Net	Gross	Net
Crude Oil Wells	**78**	**55**	**294**	**201**	**372**	**255**
Alberta	38	30	87	76	125	106
British Columbia	37	23	191	119	228	142
Saskatchewan	3	1	16	6	19	7
Bitumen Wells	**42**	**42**	**2**	**1**	**44**	**43**
Alberta	42	42	2	1	44	43
Natural Gas Wells	**331**	**161**	**333**	**187**	**664**	**348**
Alberta	206	105	72	47	278	152
British Columbia	105	54	248	136	353	190
Saskatchewan	1	1	10	4	11	4
Nova Scotia	19	2	3	0	22	2
Service Wells[1]	**-**	**-**	**317**	**208**	**317**	**208**
Alberta	-	-	118	90	118	90
British Columbia	-	-	173	112	173	112
Saskatchewan	-	-	9	4	9	4
Nova Scotia			17	1	17	1
Other[2]	**-**	**-**	**4**	**1**	**4**	**1**
Alberta	-	-	4	1	4	1
Total	**451**	**258**	**950**	**597**	**1,401**	**855**

Notes:

(1) Service Wells include disposal, injector, water source and observation wells.

(2) Other includes standing, zonally abandoned and suspended wellbores with undefined zones.

Properties with No Attributed Reserves

The following table sets forth the gross and net acres of unproved properties held by us as at December 31, 2018 and the maximum net area of unproved properties for which we expect our rights to explore, develop and exploit to expire during 2019. There are no material work commitments necessary to maintain these properties.

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. Where there are multiple discontinuous rights in a single lease, the acreage is reported only once.

Unproved Properties as at December 31, 2018

Location	Gross Acres	Net Acres	Maximum Net Acres Expected to Expire During 2019
Alberta	86,844	54,529	6,720
British Columbia	225,081	97,137	5,824
Nova Scotia	146,728	11,427	0
Saskatchewan	3,735	1,974	0
Total	**462,387**	**165,067**	**12,544**

The expiring acreage is being evaluated and attempts will be made to maintain our rights on the acreage. Historically, efforts to maintain our rights on acreage on activity have been successful.

Significant Factors or Uncertainties Relevant to Properties with no Attributed Reserves

We have minor property holdings with no attributed reserves that are largely located in North East British Columbia. As noted prior, we continually evaluate and attempt to maintain acreage where economically viable. From this process, some properties are scheduled for economic development activities while others are temporarily held inactive, sold, or allowed to expire and relinquished back to the mineral rights owner.

Forward Contracts

We use financial derivatives or fixed price contracts to manage our exposure to fluctuations in commodity prices and foreign currency exchange rates. A description of such instruments is provided in Note 16 of our annual audited consolidated financial statements and related Management's Discussion and Analysis for the year ended December 31, 2018, which may be found on our website at www.pengrowth.com, on SEDAR at www.sedar.com and on EDGAR at www.sec.gov.

Tax Horizon

We have not paid cash income tax in the past year and based upon current tax legislation, anticipated capital spending and economic conditions, we do not anticipate having to pay corporate income tax until at least 2027, partially as a result of our $2.3 billion of tax pools.

Costs Incurred

The following table outlines property acquisition, exploration and development costs that we incurred during the financial year ended December 31, 2018. These costs, which were all incurred in Canada, include only those costs which are cash or cash equivalent.

Nature of Cost	Amount ($MM)
Acquisition Costs	
Proved	—
Unproved	0
Exploration Costs[1]	(0.2)
Development Costs	64.7
Total	**64.5**

Note:

(1) Negative due to seismic sales exceeding purchases.

Exploration and Development Activities

The following table summarizes the number of wells drilled during the financial year ended December 31, 2018, all of which were drilled in Canada.

	Development		Exploration		Total	
Wells	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Gas	-	-	-	-	-	-
Oil	-	-	-	-	-	-
Bitumen	8	8	-	-	8	8
Service/Injection	-	-	-	-	-	-
Total	**8**	**8**	**-**	**-**	**8**	**8**

For a description of our most important current and likely exploration and development activities, please see "Principal Producing Properties and Operations".

Production Estimates

The following table summarizes the 2019 average daily volume of gross production estimated by GLJ for all properties held on December 31, 2018 using constant and forecast prices and costs, all of which will be produced in Canada. These estimates assume certain activities take place, such as the development of Undeveloped Reserves, and that there are no dispositions. We estimate our 2019 Company Interest production to be between 22,500 and 23,500 BOE/d.

	2019 Estimated Production					
	Constant Prices and Costs			Forecast Prices and Costs		
	Total Proved	**Total Probable**	**Total Proved Plus Probable**	**Total Proved**	**Total Probable**	**Total Proved Plus Probable**
Light Crude Oil and Medium Crude Oil (bbl/d)	373	10	383	373	10	383
Heavy Crude Oil (bbl/d)	0	0	0	0	0	0
Bitumen (bbl/d)	17,899	5	17,904	17,899	5	17,904
Conventional Natural Gas (Mcf/d)	2,572	55	2,627	2,572	55	2,627
Shale Gas (Mcf/d)	16,680	1,660	18,340	16,680	1,660	18,340
Coal Bed Methane (Mcf/d)	1,137	16	1,153	1,137	16	1,153
Natural Gas Liquids (bbl/d)	22	1	23	22	1	23
Total (BOE/d)	**21,692**	**304**	**21,996**	**21,692**	**304**	**21,996**

Production History (Netback)

The following table summarizes, for each quarter of our most recent financial year, certain of our production information in respect of our Company Interest production, product prices received, royalties paid, operating expenses and resulting operating netbacks.

	QUARTER ENDED[3]				YEAR ENDED [3]
	Mar 31, 2018	**June 30, 2018**	**Sept 30, 2018**	**Dec 31, 2018**	**Dec 31, 2018**
Barrels of Oil Equivalent[1] (including realized commodity risk management)					
Average Daily Oil Production[2] (BOE/d)	19,541	22,600	21,807	24,104	22,025
Produced petroleum revenue ($/BOE)	39.97	42.59	47.10	24.80	38.24
Royalties ($/BOE)	(2.79)	(3.99)	(3.69)	(1.67)	(3.01)
Adjusted operating expenses ($/BOE)	(10.41)	(10.11)	(10.72)	(10.87)	(10.54)
Transportation costs ($/BOE)	(2.73)	(2.67)	(2.84)	(3.02)	(2.82)
Realized commodity risk management ($/BOE)	(7.96)	(9.82)	(11.41)	(4.69)	(8.40)
Operating netback ($/BOE)	**16.08**	**16.00**	**18.44**	**4.55**	**13.47**
Light Crude Oil (excluding realized commodity risk management)					
Average Daily Oil Production[2] (bbl/d)	798	769	663	476	675
Sales price ($/bbl)	59.87	71.45	72.14	25.12	60.07
Royalties ($/bbl)	(8.82)	(8.54)	4.49)	(0.93)	(4.05)
Adjusted operating expenses ($/BOE)	(8.03))	(7.04))	(21.80)	(45.84)	(16.42)
Transportation costs ($/bbl)	(1.89)	(2.31)	(2.77)	(3.84)	(2.57)
Operating netback ($/bbl)	**41.13**	**53.56**	**52.06**	**(25.49)**	**37.03**
Bitumen (excluding realized commodity risk management)					
Average Daily Bitumen Production[2] (bbl/d)	15,118	15,876	16,408	17,866	16,325
Sales price ($/bbl)	42.33	52.47	56.64	27.50	44.32
Royalties ($/bbl)	(2.57)	(4.57)	(4.84)	(1.95)	(3.45)
Adjusted operating expenses ($/BOE)	(10.59)	(10.79)	(9.87)	(9.31)	(10.11)
Transportation costs ($/bbl)	(3.01)	(2.91)	(3.05)	(3.10)	(3.02)
Operating netback ($/bbl)	**26.16**	**34.20**	**38.88**	**13.14**	**27.74**
Natural Gas (excluding realized commodity risk management)					
Average Daily Natural Gas Production[2] (Mcf/d)	20,040	34,064	27,604	33,024	28,716
Sales price ($/Mcf)	3.88	1.77	1.61	2.37	2.27
Royalties ($/Mcf)	(0.09)	(0.12)	(0.27)	(0.11)	(0.15)
Adjusted operating expenses ($/BOE)	(1.63)	(1.39)	(2.04)	(2.02)	(1.91)
Transportation costs ($/Mcf)	(0.29)	(0.38)	(0.36)	(0.47)	(0.39)
Operating netback ($/Mcf)	**1.87**	**(0.12)**	**(1.06)**	**(0.23)**	**(0.18)**
NGL (excluding realized commodity risk management)					
Average Daily NGL Production[2] (bbl/d)	285	278	135	258	239
Sales price ($/bbl)	54.58	51.39	40.26	63.20	53.88
Royalties ($/bbl)	(20.95)	(28.39)	27.78)	(3.37)	(11.37)
Adjusted operating expenses ($/BOE)	(13.08)	(15.58)	(10.91)	(29.34)	(5.24)
Transportation costs ($/bbl	0.00	0.00	0.00	0.00	0.00
Operating netback ($/bbl)	**20.55**	**7.42**	**57.13**	**30.49**	**37.27**

Notes:

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

(2) Before the deductions of royalties.

(3) All production occurred in Canada

INDUSTRY CONDITIONS

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

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

Pricing and Marketing in Canada

Crude Oil

Producers of crude oil are entitled to negotiate sales contracts directly with crude oil purchasers, which results in the market determining the price of crude oil. Worldwide supply and demand factors primarily determine 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. The price received by a natural gas producer depends, in part, on the price of competing natural gas supplies and other fuels, natural gas quality, distance to market, availability of transportation, length of contract term, weather conditions, supply/demand balance and other contractual terms. Spot and future prices can also be influenced by supply and demand fundamentals on various trading platforms.

Natural Gas Liquids

The price of NGLs 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, length of contract term, supply/demand balance and other contractual terms.

Exports from Canada

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

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 the cabinet of the Canadian federal government. Orders are issued pursuant to the Part VI Regulation for up to one or two years depending on the substance, with the exception of natural gas (other than NGLs) for which an order may be issued for up to twenty years for quantities not exceeding 30,000 m^3 per day.

As to price, exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts continue to meet certain other criteria prescribed by the NEB and the federal government.

Pengrowth does not directly enter into contracts to export its production outside of Canada.

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

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

Transportation Constraints and Market Access

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

Developing a strong network of transportation infrastructure for crude oil, natural gas and NGLs, including by means of pipelines, rail, marine and trucks, in order to obtain better access to domestic and international markets has been a significant challenge to the Canadian crude oil and natural gas industry. Improved means of access to global markets, especially the Midwest United States and export shipping terminals on the west coast of Canada, would help to alleviate the pressures of pricing discussed. 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 shipping terminals on the west coast of Canada. While certain projects are proceeding, the regulatory approval process as well as economic and political factors for transportation and other export infrastructure has led to the delay of many pipeline projects or their cancellation altogether.

Under the Canadian constitution, interprovincial and international pipelines fall within the federal government's jurisdiction and require approval by both the NEB and the cabinet of the federal government. However, recent years have seen a perceived lack of policy and regulatory certainty at a federal level. Although the current federal government recently introduced draft legislation to amend the current federal approval processes, it is uncertain when the new legislation will be brought into force and whether any changes to the draft legislation will be made before the legislation is brought into force. It is also uncertain whether any new approval process adopted by the federal government will result in a more efficient approval process. The lack of regulatory certainty is likely to have an influence on investment decisions for major projects. Even when projects are approved on a federal level, such projects often face further delays due to interference by provincial and municipal governments as well as court challenges on various issues such as indigenous title, the government's duty to consult and accommodate indigenous peoples and the sufficiency of environmental review processes, which creates further uncertainty. 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.

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

Government of Alberta Curtailment Program

In December 2018, the Government of Alberta announced that they would be temporarily curtailing production from all oil producers with more than 10,000 bbl/d of production in Alberta effective January 1, 2019 to achieve an 8.7% or 325,000 bbl/d reduction in total production for the first three months of 2019 (the "**Curtailment Program**"). The goal of this program is to address the wide differential between the price of Western Canadian Select crude oil and the price of Western Texas Intermediate crude oil (the "**Differential**")resulting from the market imbalance created by growing production, growing storage inventories, and the lack of transportation capacity for crude oil to global markets. As soon as the Curtailment Program was announced, the Differential dropped substantially.

Pengrowth is impacted by the Curtailment Program. Thanks to early engagement with the Government of Alberta, the government revised their baseline calculation methodology, which originally was excessively punitive to companies that were increasing their production over the course of 2018. Based on the revised baseline calculation methodology, we are permitted to produce up to 17,496 bbl/d for the months of February and March. Pengrowth has also made use of Alberta's Curtailment Consolidation and Transfer framework to increase our production limit. This has allowed Pengrowth to proceed without altering its production guidance for 2019.

Pengrowth is unable to participate fully in the lower Differential that has resulted from the Curtailment Program due to the physical apportionment protected sales contracts we have entered into on 17,500 bbl/d at an average fixed Differential of (US$18.68) to WTI.

While the Curtailment Program originally contemplated being in full force for the first three months with curtailment relief thereafter, it is not known how long the full Curtailment Program will last, when it will be tapered, and to what extent it will be tapered. The Government of Alberta indicated that it expected the curtailment rate to gradually drop over the course of 2019. However, as a result of decreasing Differential 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 bbl/d to a maximum output of approximately 3.63 million bbl/d.

On March 2, 2019, Enbridge announced that operations on their Line 3 pipeline, which were expected to commence in the fourth quarter of 2019, would be delayed by another year due to permitting delays. This delay could cause Alberta's Curtailment Program to continue longer than initially contemplated.

International Trade Agreements

In November, 2018, Canada, the United States and Mexico signed the Canada-United States-Mexico Agreement ("**USMCA**") to replace the North American Free Trade Agreement ("**NAFTA**"), which US President Donald J. Trump has indicated his intention to withdraw from. NAFTA, however, remains the North American trade agreement currently in force until the legislative bodies of the three signatory countries ratify the USMCA. There is uncertainty surrounding the ratification of the USMCA, when or if NAFTA will come to an end, further contributing to general uncertainty around the future of United States-Canada trade. Under the terms of USMCA, Canada will no longer be subject to the proportionality provisions in NAFTA's energy chapter, which should permit the expansion of oil and gas exports beyond the US, and a change to the oil and gas rules of origin will allow Canadian exporters to more easily qualify for duty-free treatment for shipments to the US. In particular, the origin of the diluent that is used to facilitate the transportation of crude petroleum oils is disregarded, provided that the diluent constitutes no more than 40 per cent by volume of the good. The US 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. Any changes to the USMCA (or in the event the USMCA is not ratified) could have an impact on Western Canada's crude oil and natural gas industry at large, including the Corporation's business.

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

Canada has also pursued a number of other international free trade agreements with other countries around the world. As a result, a number of free trade or similar agreements are in force between Canada and certain other countries while in other circumstances Canada has been unsuccessful in its efforts. Canada and the European Union recently agreed to the Comprehensive Economic and Trade Agreement ("**CETA**"), which provides for duty-free, quota-free market access for Canadian 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, on December 30, 2018, the Comprehensive and Progressive Agreement for Trans-Pacific Partnership ("**CPTPP**") entered into force among Canada, Australia, Japan, Mexico, New Zealand and Singapore. On January 14, 2019, the CPTPP entered into force for Vietnam. The CPTPP is intended to allow for preferential market access among the signatories. While it is uncertain what effect CETA, CPTPP or any other trade agreements will have on the oil and gas industry in Canada, the lack of available infrastructure for the offshore export of oil and gas may limit the ability of Canadian oil and gas producers to benefit from such trade agreements.

Land Tenure

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

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

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

In addition to Crown ownership of the rights to crude oil and natural gas, private ownership of crude oil and natural gas (i.e. freehold mineral lands) also exists in the provinces of Alberta, British Columbia and Saskatchewan. In each of the provinces of Alberta, British Columbia and Saskatchewan approximately 19%, 6% and 30%, respectively, of the mineral rights are owned by private freehold owners. Rights to explore for and produce such crude oil and natural gas are granted by a lease or other contract on such terms and conditions as may be negotiated between the owner of such mineral rights and crude oil and natural gas explorers and producers.

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

Royalties and Incentives

General

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

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

In addition, the federal government may from time to time provide incentives to the crude oil and natural gas industry. In November 2018, the federal government announced its plans to implement an accelerated investment incentive, which will provide crude oil and natural gas businesses with eligible Canadian development expenses and Canadian crude 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 crude oil and natural gas industry in light of worsening commodity price differentials. The aid package, however, is mostly in the form of loans and is earmarked for crude oil and natural gas projects related to economic diversification as well as direct funding for clean growth oil and gas projects.

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

Alberta

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

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

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

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

Oil sands production is also subject to Alberta's royalty regime. The Modernized Framework did not change the oil sands royalty framework. Prior to payout of an oil sands project, the royalty is payable on gross revenues of an oil sands project. Gross revenue royalty rates range between 1% and 9% depending on the market price of crude oil, determined using the average monthly price, expressed in Canadian dollars, for Western Texas Intermediate crude oil at Cushing, Oklahoma. Rates are 1% when the market price of crude oil is less than or equal to $55 per barrel and increase for every dollar of market price of crude oil increase to a maximum of 9% when crude oil is priced at $120 or higher. After payout, the royalty payable is the greater of the gross revenue royalty based on the gross revenue royalty rate of between 1% and 9% and the net revenue royalty based on the net revenue royalty rate. Net revenue royalty rates start at 25% and increase for every dollar of market price of crude oil increase above $55 up to 40% when crude oil is priced at $120 or higher.

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

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

British Columbia

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

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

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

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

Saskatchewan

In Saskatchewan, the Crown owns approximately 80% of the crude oil and natural gas rights, with the remainder being freehold lands. For Crown lands, taxes (the "**Resource Surcharge**") and royalties are applicable to revenue generated by entities focused on crude oil and natural gas operations. The Resource Surcharge rate is 3% of the value of sales of all crude oil and natural gas produced from wells drilled in Saskatchewan prior to October 1, 2002. For crude oil and natural gas produced from wells drilled in Saskatchewan after September 30, 2002, the Resource Surcharge rate is 1.7% of the value of sales. In addition, a mineral rights tax is charged to mineral rights holders paid on an annual basis at the rate of $1.50 per acre owned.

In addition to such surcharges and taxes, the Crown royalty payable in respect of crude oil depends on the type and vintage of crude oil, the quantity of crude oil produced in a month, the value of the crude oil produced and specified adjustment factors determined monthly by the provincial government. The ultimate royalty payable ranges from 5% to 20% depending on the classification of the crude oil, and additional marginal royalty rates may apply, between 30% and 45%, where average wellhead prices received are above base prices. This means that producers may pay varying royalties each month, depending on pricing factors, governmental adjustments and the underlying characteristics of the producer's assets.

The amount payable as a Crown royalty in respect of production of natural gas and NGLs is determined by a sliding scale based on the monthly provincial average gas price published by the Government of Saskatchewan, the quantity produced in a given month, the type of natural gas, the classification of the natural gas and the finished drilling date of the respective well. Similar to crude oil royalties, the royalties payable on natural gas will range from 5% to 20%, and additional marginal royalty rates may apply between 30% to 45%, where average wellhead prices are above base prices. Again, this means that producers may pay varying royalties each month, depending on pricing factors, governmental adjustments and the underlying characteristics of the producer's assets.

The Government of Saskatchewan currently provides a number of targeted incentive programs. These include both royalty reduction and incentive volume programs, with targeted programs in effect for certain vertical crude oil wells, exploratory gas wells, horizontal crude oil and natural gas wells, enhanced crude oil recovery wells and high water-cut crude oil wells.

For production from freehold lands, producers must pay a freehold production tax, determined by first determining the Crown royalty rate, and then subtracting a calculated production tax factor. Depending on the classification of the petroleum substance produced, this subtraction factor may range between 6.9 and 12.5, however, in certain circumstances, the minimum rate for freehold production tax can be zero. This means that the ultimate tax payable to the Crown by producers on freehold lands will vary based on the underlying characteristics of the producer's assets.

Freehold and Other Types of Non-Crown Royalties

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

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

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

Regulatory Authorities and Environmental Regulation

General

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

Federal

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

On June 20, 2016, the federal government launched a review of current environmental and regulatory processes. On February 8, 2018, the Government of Canada introduced draft legislation to overhaul the existing environmental assessment process and replace the NEB with the Canadian Energy Regulator ("**CER**"). Pursuant to the draft legislation, the Impact Assessment Agency of Canada (the "**Agency**") would replace the Canadian Environmental Assessment Agency. It appears that additional categories of projects may be included within the new impact assessment process, such as large-scale wind power facilities and in-situ oilsands facilities. The revamped approval process for applicable major developments will have specific legislated timelines at each stage of the formal impact assessment process. The Agency's process would focus on: (i) early engagement by proponents to engage the Agency and all stakeholders such as the 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 of the federal government; (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 the notable exception that the CER would no longer have primary responsibility in the consideration of the 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 federal government'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 proponents of major projects remains unclear.

On May 12, 2017, the federal government introduced the *Oil Tanker Moratorium Act* in Parliament. 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 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 single regulator responsible for all resource development in 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 objective behind a single regulator is an enhanced regulatory regime that is intended to be efficient, attractive to business and investors and effective in supporting public safety, environmental management and resource conservation while respecting the rights of landowners.

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.

British Columbia

In British Columbia, the *Oil and Gas Activities Act* (the "**OGAA**") impacts conventional crude oil and natural gas producers, shale gas producers and other operators of crude oil and natural gas facilities in the province. Under the OGAA, the British Columbia Oil and Gas Commission (the "**Commission**") has broad powers, particularly with respect to compliance and enforcement and the setting of technical safety and operational standards for crude oil and natural gas activities. The *Environmental Protection and Management Regulation* establishes the government's environmental objectives for water, riparian habitats, wildlife and wildlife habitat, old-growth forests and cultural heritage resources. The OGAA requires the Commission to consider these environmental objectives in deciding whether or not to authorize a crude oil or natural gas activity. In addition, although not an exclusively environmental statute, the *Petroleum and Natural Gas Act*, in conjunction with the OGAA, requires proponents to obtain various approvals before undertaking exploration or production work, such as geophysical licences, geophysical exploration project approvals, permits for the exclusive right to do geological work and geophysical exploration work, and well, test hole and water-source well authorizations. Such approvals are given subject to environmental considerations and licences and project approvals can be suspended or cancelled for failure to comply with this legislation or its regulations.

The Government of British Columbia recently passed Bill 51 - 2018: Environmental Assessment Act, which replaces the environmental assessment regime that has been in place since 2002. The Government expects that the updated Environmental Assessment Act will enter into force in late 2019. The amendments will subject proposed projects to an enhanced environmental review process similar in substance to the federal environmental assessment process, as well as enhance indigenous engagement in the project approval process with an emphasis on consensus-building.

Saskatchewan

The Saskatchewan Ministry of Energy and Resources is the primary regulator of crude oil and natural gas activities in the province. In May 2011, the Government of Saskatchewan passed changes to *The Oil and Gas Conservation Act* (the "**SKOGCA**"), the act governing the regulation of resource development operations in the province. Although the associated Bill received Royal Assent on May 18, 2011, it was not proclaimed into force until April 1, 2012, in conjunction with the release of *The Oil and Gas Conservation Regulations, 2012* (the "**OGCR**") and *The Petroleum Registry and Electronic Documents Regulations* (the "**Registry Regulations**"). The aim of the amendments to the SKOGCA, and the associated regulations, is to provide resource companies investing in Saskatchewan's energy and resource industries with the best support services and business and regulatory systems available. With the enactment of the Registry Regulations and the OGCR, the Government of Saskatchewan has implemented a number of operational requirements, including the increased demand for record-keeping, increased testing requirements for injection wells and increased investigation and enforcement powers; and, procedural requirements including those related to Saskatchewan's participation as partner in Petrinex (the petroleum information network utilized by the Government of Alberta and British Columbia).

Liability Management Rating Program

Alberta

The AER administers the Licensee Liability Rating Program (the "**AB LLR Program**"). The AB LLR Program is a liability management program governing most conventional upstream crude oil and natural gas wells, facilities and pipelines. Alberta's *Oil and Gas Conservation Act* (the "**OGCA**") establishes an orphan fund (the "**Orphan Fund**") to pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline included in the AB LLR Program if a licensee or working interest participant ("**WIP**") becomes insolvent or is unable to meet its obligations. The Orphan Fund is funded by licensees in the AB LLR Program through a levy administered by the AER. The AB LLR Program is designed to minimize the risk to the Orphan Fund posed by unfunded liability of licensees and to prevent the taxpayers of Alberta from incurring costs to suspend, abandon, remediate and reclaim wells, facilities or pipelines. The AB LLR Program requires a licensee whose deemed liabilities exceed its deemed assets to provide the AER with a security deposit. The ratio of deemed assets to deemed liabilities is assessed once each month and where a security deposit is deemed to be required, the failure to post any required amounts may result in the initiation of enforcement action by the AER. The AER publishes the liability management rating for each licensee on a monthly basis on its public website.

The recent decision of the Supreme Court of Canada ("**SCC**") in Orphan Well Association, et al. v. Grant Thornton Limited, et al, 2019 SCC 5 (commonly known as "**Redwater**") held that reclamation and abandonment liabilities, including the AB LLR Program, of insolvent oil and gas companies must be dealt with before distribution of the company's assets or proceeds from the sale of those assets to its creditors, including secured creditors. It is expected that the decision of the SCC in Redwater may result in increased constraint in accessing credit by oil and gas companies as the decision has the effect of affording priority to certain environmental and reclamation obligations that lenders are unable to quantify at the time credit is advanced. The full extent of the regulatory implications of the Redwater decision remain unclear.

In response to Redwater, the AER issued a news release on January 31, 2019 confirming that they are working to understand the full implications of the SCC's decision. As such, further legislative changes may be forthcoming which could result in additional obligations for the Company and/or different requirements. The AER's Directive 067: Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals, which deals with licence eligibility to operate wells and facilities, was amended and now requires extensive corporate governance and shareholder information, with a particular focus on any previous companies of directors and officers that have 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 are assessed on a non-routine basis and the AER now requires all transferees to demonstrate that they have a liability management rating ("**LMR**"), being the ratio of a licensee's assets to liabilities, of 2.0 or higher immediately following the transfer, or to otherwise prove that it can satisfy its abandonment and reclamation obligations.

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: Suspension Requirements for Wells ("**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. The IWCP completed its third year on March 31, 2017.

British Columbia

The Commission oversees a similar Liability Management Rating Program (the "**BC LMR Program**"), which is designed to manage public liability exposure related to crude oil and natural gas activities by ensuring that permit holders carry the financial risks and regulatory responsibility of their operations through to regulatory closure. Under the BC LMR Program, the British Columbia Oil and Gas Commission determines the required security deposits for permit holders under the OGAA. The LMR is the ratio of a permit holder's deemed assets to deemed liabilities. Permit holders whose deemed liabilities exceed deemed assets (i.e., an LMR of below a ratio of 1.0) will be considered at-risk and reviewed for a security deposit. Permit holders that fail to comply with security deposit requirements are deemed non-compliant under the OGAA and enter the compliance and enforcement framework.

In the spring of 2018 the Government of British Columbia passed certain amendments to the OGAA (the "**Amendments**") which when brought into force, will replace the orphan site reclamation fund tax currently paid by permit holders with a levy paid to the Orphan Site Reclamation Fund ("**OSRF**"). Similar to Alberta's Orphan Fund, the OSRF is an industry-funded program created to address the abandonment and reclamation costs for orphan sites. Permit holders currently make monthly payments of $0.03 per 1,000 cubic metres of marketable gas produced and $0.06 per cubic meter of petroleum produced. The Amendments will require permit holders to pay their proportionate share of the regulated amount of the levy, calculated using each permit holder's proportionate share of the total liabilities of all permit holders required to contribute to the fund. The Amendments permit the B.C. Commission to impose more than one levy in a given calendar year. It is not clear when these provisions of the Amendments changing from a tax based on production to a liability-based payment will be brought into force.

Saskatchewan

The Government of Saskatchewan Ministry of Energy and Resources administrates the Licensee Liability Rating Program (the "**SK LLR Program**"). The SK LLR Program is designed to assess and manage the financial risk that a licensee's well and facility abandonment and reclamation liabilities pose to an orphan fund (the "**Oil and Gas Orphan Fund**") established under the SKOGCA. The Oil and Gas Orphan Fund is responsible for carrying out the abandonment and reclamation of wells and facilities contained within the SK LLR Program when a licensee or WIP is defunct or missing. The SK LLR Program requires a licensee whose deemed liabilities exceed its deemed assets (i.e., an LLR of below 1.0) to post a security deposit. The ratio of deemed assets to deemed liabilities is assessed once each month for all licensees of crude oil, natural gas and service wells and upstream crude oil and natural gas facilities. The Government of Saskatchewan Ministry of Energy and Resources may amend its rules and legislative scheme in light of the Redwater decision.

Climate Change Regulation

Climate change regulation at both the federal and provincial level has the potential to significantly affect the regulatory environment of the crude 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 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 February 1, 2019, 195 parties to the convention signed the Paris Agreement.

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 "**Framework**"). The 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 crude 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 crude 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 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 *Climate Leadership Act* came into force on January 1, 2017 and enabled a carbon levy that increased from $20 to $30 per tonne on January 1, 2018. The levy is anticipated to increase again in 2021 in line with the federal legislation. On December 14, 2016, the *Oil Sands Emissions Limit Act* came into force, establishing a 100 megatonne limit for GHG emissions from all oil sands sites, excluding some attributable to upgraders, the electric energy portion of cogeneration and other prescribed emissions.

The *Carbon Competitiveness Incentives Regulation* (the "**CCIR**"), which replaces the *Specified Gas Emitters Regulation*, came into effect on January 1, 2018. Unlike the previous regulation, which set emission reduction requirements, the CCIR imposes an output-based benchmark on competitors in the same emitting industry. The aim is to reduce annual GHG emissions by 20 megatonnes by 2020 and 50 megatonnes by 2030, and targets facilities that emit more than 100,000 tonnes of GHGs per year and mandates quarterly and final reporting requirements. 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 federal Framework.

Under the CLP, the AER was tasked with developing requirements to reduce methane emissions from upstream oil and gas operations by 45% relative to 2014 levels by 2025. To affect this, on December 13, 2018, the Alberta Ministry of Energy and the AER updated the AER's Directive 060: Upstream Petroleum Industry Flaring, Incinerating and Venting and Directive 017: Measurement Requirements for Oil and Gas Operations with methane requirements to meet Alberta's target. In addition, Energy plans to seek equivalency with the federal methane regulations.

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.

British Columbia

On August 19, 2016, the Government of British Columbia launched its Climate Leadership Plan, which aims to reduce British Columbia's net annual emissions by up to 25 million tonnes below current forecasts by 2050 and recommit the province to achieving its target of reducing emissions by 80% below 2007 levels by 2050. Additionally, British Columbia seeks to generate at least 93% of its electricity from clean or renewable sources and build the infrastructure necessary to transmit it. The legislation established no date for this target.

Beginning April 1, 2018, British Columbia's carbon tax rate was increased to $35 per tonne of carbon dioxide equivalent emissions. The tax rate will increase each year by $5 per tonne until it reaches $50 per tonne in 2021. New revenues generated from increasing the carbon tax will be used to provide carbon tax relief and protect affordability, maintain industry competitiveness and encourage new green initiatives.

On January 1, 2016, the Greenhouse Gas Industrial Reporting and Control Act (the "**GGIRCA**") came into effect, which streamlined the regulatory process for large emitting facilities. The GGIRCA sets out various performance standards for different industrial sectors and provides for emissions offsets through the purchase of credits or through emission offsetting projects.

In December 2018, the Government of British Columbia released its CleanBC plan aimed at reducing climate pollution. The plan discusses many approaches to this, including reducing methane emissions from natural gas development and introducing a regulatory framework for safe and effective underground carbon storage and direct air capture. The CleanBC Plan indicates that the province will put in place a minimum requirement for 15% renewable content in natural gas by 2030.

On December 5, 2018, the Government of British Columbia announced an updated clean energy plan, "CleanBC", which seeks to ensure that British Columbia achieves 75% of its GHG emissions reduction target by 2030. The CleanBC plan includes a number of strategies targeting the industrial, transportation construction, and waste sectors of the British Columbia economy. Key initiatives include: i) increasing the generation of electricity from clean and renewable energy sources; ii) imposing a 15% renewable content requirement in natural gas by 2030; iii) requiring fuel suppliers to reduce the carbon intensity of diesel and gasoline by 20% by 2030; iv) investing in the electrification of oil and gas production; v) reducing 45% of methane emissions associated with natural gas production; and vi) incentivizing the adoption of zero emissions vehicles. On January 16, 2019, the B.C. Commission announced a series of amendments to the B.C. Drilling and Production Regulation that will require facility and well permit holders to, among other things, reduce natural gas leaks and curb monthly natural gas emissions from their equipment and operations. These new rules will come into effect on January 1, 2020.

Saskatchewan

On May 11, 2009, the Government of Saskatchewan announced the Management and Reduction of Greenhouse Gases Act (the "**MRGGA**") to regulate GHG emissions in the province. The MRGGA, partially proclaimed into force on January 1, 2018, establishes a framework to reduce GHG emissions by 20% of 2006 levels by 2020.

In December, 2017, the Government of Saskatchewan released its Prairie Resilience climate change strategy, which outlined multiple commitments to make Saskatchewan more resilient to the climatic, economic and policy impacts of climate change. Under this strategy, the Government proclaimed The Management and Reduction of Greenhouse Gases (General and Electricity Producer) Regulations, which took effect January 1, 2018 and are the next step in an equivalency agreement for provincial coal-fired emissions regulation. Facilities emitting over 10,000 tonnes of GHG must now annually report to the province. In addition, the Government announced output-based performance standards that will regulate large industrial facilities to reduce GHG by an additional 5.3 million tonnes from 2019 to 2030, achieving 10% reductions by 2030, as well as introduced the Methane Action Plan and The Oil and Gas Emissions Management Regulations, which will achieve a 4.5 million tonnes carbon dioxide equivalent annual reduction by 2025 and a total reduction of 38.2 million tonnes CO2e between 2020 and 2030.

*General Discussio*n

Since the 2018 release of new Federal and Provincial Emission regulations, we are anticipating increased direct and indirect costs related to operational emissions. Our operations are now governed by the new regulations and, for 2018, our compliance costs were approximately $1.8 million. Currently, our operations are able to bear these costs. While we expect the costs from various GHG regulations, both existing and proposed, to increase costs as production levels rise and the cost per tonne of carbon increases, some of these costs can be mitigated and offset through the favourable treatment that co-generation facilities receive. That said, there is the potential for direct and indirect costs to adversely affect our business, operations and financial results. Equipment replacement to meet future emission standards may be required and could materially impact capital costs for the corporation. Failure to meet emission compliance benchmarks may adversely affect our business materially by inflating payments to the Climate Management Fund or increasing the cost for purchasing offset carbon credits. There is also a risk that one or more levels of government could impose additional emission reduction requirements, increase the cost of carbon credits, or increase taxes on emissions produced by us or by the consumers of our products. The imposition of such measures might negatively affect our costs and prices for our products and have an adverse effect on earnings and results of operations.

Accountability and Transparency

In 2015, the federal government's *Extractive Sector Transparency Measures Act* (the "**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 CAD$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

Our business involves the development and production of oil and natural gas in Western Canada. There are a number of risks associated with our operations, some that impact the oil and natural gas industry as a whole and others that are unique to our operations. Many of these risks are beyond our control.

The following is a summary of certain risk factors relating to our business. These risk factors should be read in conjunction with the detailed information appearing elsewhere in this AIF. If any of the following risks or uncertainties occurs, our production, revenue and financial condition could be materially impaired. In that event, the market price of our Common Shares could decline and investors could lose all or part of their investment. Additional risks and uncertainties presently unknown, or that are not believed to be material at this time, may also impair or have a material adverse effect on the Corporation's operations and financial condition. In addition to the risks described elsewhere and the other information contained in this AIF, investors should carefully consider each of and the cumulative effect of all of the following risk factors. **Additional risks are described under the heading "Business Risks" in our Management's Discussion and Analysis for the year ended December 31, 2018.**

Operational Risks

Low oil and natural gas prices could have a material adverse effect on our results of operations and financial condition, which, in turn, could negatively affect the market price of the Common Shares.

Our financial performance and the market price of our Common Shares depends, in part, on the prices we receive for our oil and natural gas production. Oil and natural gas prices can fluctuate widely on a month-to-month, or even a day-to-day, basis in response to a variety of factors that are beyond our control. Extended periods of lower commodity prices may reduce our level of spending for oil and gas exploration and development, and may have a material adverse effect on our results of operations. Crude oil and natural gas are commodities that are price-sensitive to numerous worldwide factors, many of which are beyond our control. These factors include, but are not limited to:

- global energy policy, including the ability of OPEC to set and maintain production levels for oil and non-OPEC member countries' decisions on production levels;
- worldwide geo-political conditions;
- worldwide economic conditions including ongoing credit and liquidity concerns;
- the costs of exploring for, developing, producing and transporting crude oil, natural gas and natural gas liquids;
- weather conditions including weather-related disruptions to the North American natural gas supply;

- the supply and price of foreign and North American produced oil and natural gas;
- the level of consumer demand;
- the price and availability of alternative fuels;
- the proximity to, and capacity of, transportation facilities;
- the effect of worldwide energy conservation measures; and
- domestic and foreign government regulation and taxes.

Recent market events and conditions, including global excess oil and natural gas supply, recent actions taken by OPEC and non-OPEC member countries' decisions on production levels, slowing growth in emerging economies, market volatility and disruptions in Asia, sovereign debt levels in various countries and political upheavals, have caused significant weakness and volatility in commodity prices. North American crude oil price differentials are also expected to continue to be volatile throughout 2019 which will have an impact on crude oil prices for Canadian producers.

These events and conditions have caused a significant decrease in the valuation of oil and gas companies and a decrease in confidence in the oil and 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, liquefied natural gas plants and other facilities to provide better access to markets for the oil and gas industry in Western Canada has led to downward price pressure on oil and gas produced in Western Canada and additional uncertainty and reduced confidence in the oil and gas industry in Western Canada.

Uncertainty in the capital markets may restrict the availability or increase the cost of capital or borrowing required for future development and acquisitions.

The future development of our business may be dependent on our ability to obtain additional capital including, but not limited to, debt and equity financing. Unpredictable financial markets and the associated credit impacts may impede our ability to secure and maintain cost effective financing and limit our ability to achieve timely access to capital markets on acceptable terms and conditions. If external sources of capital become limited or unavailable, our ability to make capital investments, continue our business plan, meet all of our financial obligations as they come due and maintain existing properties may be impaired. Should a lack of financing and uncertainty in the capital markets adversely impact our ability to refinance debt, additional equity may be issued which could have a dilutive effect on Shareholders.

Our ability to obtain additional capital is dependent on, among other things, a general interest in energy industry investments and, in particular, interest in our securities along with our ability to maintain our credit ratings. If we are unable to maintain our indebtedness and financial ratios at levels acceptable to our credit rating agencies, or should our business prospects deteriorate, our credit ratings could be downgraded, which would adversely affect the value of our outstanding securities and existing debt and our ability to obtain new financing and may increase our borrowing costs.

From time to time we may enter into transactions which may be financed in whole or in part with debt. The level of our indebtedness from time to time could impair our ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise.

Uncertainty in the industry may restrict the availability or increase the cost of borrowing required for future development and acquisitions.

Due to the conditions in the oil and gas industry and global economic and political volatility, we may from time to time have restricted access to capital and increased borrowing costs. The current conditions in the oil and gas industry have negatively impacted the ability of oil and gas companies to access additional financing. Commodity prices continue to be depressed and have fallen dramatically since 2014. Prices remain volatile as a result of various factors, including actions taken to limit OPEC and non-OPEC production and increasing production by US shale producers. There remains a substantial amount of uncertainty as to when and if commodity prices will recover. Continued depressed oil and natural gas prices have caused decreases, and may cause further decreases, in our cash flow.

To the extent that external sources of capital become limited, unavailable or available on onerous terms, our ability to access sufficient capital for our capital expenditures and acquisitions could be impaired and, as a result, may have a material adverse effect on our ability to execute our business strategy and on our financial condition. There can be no assurance that financing will be available or sufficient to meet these requirements or for other corporate purposes or, if financing is available, that it will be on terms appropriate and acceptable to us. Should the lack of financing and uncertainty in the capital markets adversely impact our ability to refinance debt, additional equity may be issued resulting in a dilutive effect on current and future Shareholders. Failure to obtain financing on a timely basis could cause us to forfeit our interest in certain properties, miss certain acquisition opportunities, reduce or terminate operations or delay development and production activities.

The trading price of our Common Shares is subject to substantial volatility often based on factors related and unrelated to our financial performance or prospects.

Factors that could affect the market price of our Common Shares that are unrelated to our performance could include domestic and global commodity prices, market perceptions of the attractiveness of particular industries, macroeconomic developments nationally, within North America or globally, domestic and global commodity prices or current perceptions of the oil and gas market. In certain jurisdictions, institutions, including government sponsored entities, have determined to decrease their ownership in oil and 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 price of our Common Shares could be subject to significant fluctuations in response to variations in our operating results, financial condition, liquidity and other internal factors. The price at which our Common Shares will trade cannot be accurately predicted.

Actual production, reserves and resources will vary from estimates, and those variations could be material and may negatively affect the market price of the Common Shares.

The value of the Common Shares will depend upon, among other things, our reserves and resources. In making strategic decisions, we rely upon reports prepared by our independent reserve engineers and our own internal estimates. Estimating future production, reserves and resources is inherently uncertain. Ultimately, actual production, revenues and expenditures for the underlying properties will vary from estimates and those variations could be material. Changes in the prices of, and markets for, oil and natural gas from those anticipated at the time of making such assessments will affect the return on, and value of, our Common Shares. The reserves, resources and cash flow information contained in the reserve information herein represent estimates only. Petroleum engineers consider many factors and make assumptions in estimating reserves and resources.

Those factors and assumptions include, among others:

- historical production from the area compared with production rates from similar producing areas;
- the assumed effect of government regulation;
- assumptions about future commodity prices, exchange rates, production and development costs, capital expenditures, abandonment costs, environmental liabilities, and applicable royalty regimes;
- initial production rates;
- production decline rates;
- ultimate recovery of reserves and resources;
- marketability of production; and
- other government levies that may be imposed over the producing life of reserves.

If any of these factors and assumptions prove to be inaccurate, our actual results may vary materially from our reserve and resource estimates. Many of these factors are subject to change and are beyond our control. In addition, all such assessments involve a measure of geological and engineering uncertainty that could result in lower production and reserves and resources than anticipated. A portion of our reserves are classified as “undeveloped” and are subject to greater uncertainty than reserves classified as “developed”.

In accordance with normal industry practices, we engage independent petroleum engineers to conduct a detailed engineering evaluation of our oil and gas properties for the purpose of estimating our reserves as part of our year end reporting process. As a result of that evaluation, we may increase or decrease the estimates of our reserves. We do not consider an increase or decrease in the estimates of our reserves in the range of up to five percent to be material or inconsistent with normal industry practice. Any significant reduction to the estimates of our reserves resulting from any such evaluation could have a material adverse effect on the value of our Common Shares.

If oil and natural gas prices remain at their current levels or decrease further, our estimates of total reserves and the values thereof may be reduced.

Our reserves as at December 31, 2018 are estimated using both constant and forecast pricing that escalates in future years. Forecast prices are substantially above current oil and natural gas prices. If oil and gas prices stay at current levels or drop further, our 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 us to re-evaluate our development plans and reduce or eliminate various projects with marginal economics.

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

In addition, lower commodity prices have restricted, and are anticipated to continue to restrict, our cash flow resulting in a reduced capital expenditure budget. As a result, we may not be able to replace our production with additional reserves and both our production and reserves could be reduced on a year over year basis.

The amount of oil and natural gas that we can produce and sell is subject to the accessibility, availability, proximity and capacity of gathering, processing and pipeline systems.

We deliver our products through gathering, processing and pipeline systems some of which we do not own. Access to the pipeline capacity for the transport of crude oil into the United States has become inadequate for the amount of Canadian production being exported to the United States and has recently resulted in significantly lower amounts being realized by Canadian producers compared with the WTI price for crude oil. Although opportunities to move oil by rail continue to grow and will provide new outlets for access to North American refineries otherwise not reachable via existing pipeline infrastructure, supply in excess of current pipeline and refining capacity is expected to continue to exist. Although we currently do not directly transport oil by rail, we could be affected by both positive and negative impacts (i.e. pricing of our oil sales from supply/demand issues) that could result from significant fluctuations to this transport method. Material structural changes are required to reduce these bottlenecks and the resulting steep price discounts. Although pipeline expansions are ongoing, the lack of firm pipeline capacity continues to affect the oil and natural gas industry and limits the ability to produce and market petroleum and natural gas production. In addition, the pro-rationing of capacity on inter-provincial pipeline systems also continues to affect the ability to export oil and natural gas.

The lack of firm pipeline capacity continues to affect the oil industry and limit the ability to transport produced oil and gas to market. In addition, the pro-rationing of capacity on inter-provincial pipeline systems continues to affect the ability to export oil. Unexpected shut downs or curtailment of capacity of pipelines for maintenance or integrity work or because of actions taken by regulators could also affect our production, operations and financial results. Furthermore, 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 uncertainty in constructing new infrastructure systems and facilities could harm our business and, in turn, our financial condition, results of operations and cash flows.

The lack of access to capacity in any of the gathering, processing and pipeline systems, and in particular the processing facilities, could result in our inability to realize the full economic potential of our production or in a reduction of the price offered for our production. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays or uncertainty in constructing new infrastructure systems and facilities could harm our business and, in turn, our financial condition.

A portion of our production may, from time to time, be processed through facilities owned by third parties and which we do not have control of. From time to time, these facilities may discontinue or decrease operations either as a result of normal servicing requirements or as a result of unexpected events. A discontinuance or decrease of operations could materially adversely affect our ability to process our production and to deliver the same for sale. Certain pipeline leaks have gained media and other stakeholder attention and may result in additional regulation or changes in law which could impede the conduct of our business or make our operations more expensive.

Announcements and actions taken by the governments of British Columbia and Alberta relating to 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 recently 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, with an aim 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.

Following major accidents in Lac-Megantic, Quebec and North Dakota, the Transportation Safety Board of Canada and the U.S. National Transportation Board have recommended additional regulations for railway tank cars carrying crude oil. These recommendations include, among others, the imposition of higher standards for all DOT-111 tank cars carrying crude oil and the increased auditing of shippers to ensure they properly classify hazardous materials and have adequate safety plans in place. The increased regulation of rail transportation may reduce the ability of railway lines to alleviate pipeline capacity issues and add 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.

Our financial performance also depends on revenues from the sale of commodities which differ in quality and location from underlying commodity prices quoted on financial exchanges. Of particular importance are the price differentials between our light/medium crude oil, heavy crude oil (in particular the light/heavy differential) and bitumen and quoted market prices. Not only are these discounts influenced by regional supply and demand factors, they are also influenced by other factors such as transportation costs, capacity and interruptions; refining demand; the availability and cost of diluent used to blend and transport product; and the quality of the oil produced, all of which are beyond our control.

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.

A decline in our ability to market our oil and natural gas production could have a material adverse effect on production levels or on the price received for production, which, in turn, could affect the market price of the Common Shares.

The marketability of our production depends in part upon the availability, proximity and capacity of gas gathering systems, pipelines, railway lines and processing and storage facilities. United States federal and state and Canadian federal and provincial regulation of oil and gas production and transportation, general economic and political conditions, changes in supply and demand, market conditions and other conditions affecting infrastructure systems and facilities could adversely affect our ability to produce and market oil and natural gas. If market factors dramatically change, the financial impact on us could be substantial. The availability of markets is beyond our control.

The lack of firm pipeline capacity continues to affect the oil industry and limit the ability to transport produced oil and gas to market. In addition, the pro-rationing of capacity on inter-provincial pipeline systems continues to affect the ability to export oil. Unexpected shut downs or curtailment of capacity of pipelines for maintenance or integrity work or because of actions taken by regulators could also affect our production, operations and financial results. Furthermore, 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 uncertainty in constructing new infrastructure systems and facilities could harm our business and, in turn, our financial condition, results of operations and cash flows.

Announcements and actions taken by the governments of British Columbia and Alberta relating to 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 recently 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, with an aim 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.

Following major accidents in Lac-Megantic, Quebec and North Dakota, the Transportation Safety Board of Canada and the US National Transportation Board have 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, imposed a per tonne levy of $1.65 (to be adjusted annually) 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 eventually phase out DOT-111 tank cars carrying crude oil. The increased regulation of rail transportation may reduce the ability of railway lines to alleviate pipeline capacity issues 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.

Our financial performance also depends on revenues from the sale of commodities which differ in quality and location from underlying commodity prices quoted on financial exchanges. Of particular importance are the price differentials between our light/medium crude oil, heavy crude oil (in particular the light/heavy differential) and bitumen and quoted market prices. Not only are these discounts influenced by regional supply and demand factors, they are also influenced by other factors such as transportation costs, capacity and interruptions; refining demand; the availability and cost of diluent used to blend and transport product; and the quality of the oil produced, all of which are beyond our control.

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.

If we are unable to acquire or develop additional reserves, the value of the Common Shares may decline.

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. Our long-term commercial success depends on our ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, our existing reserves, and the production from them, will decline over time as we produce from such reserves. A future increase in our reserves will depend on both our ability to explore and develop our existing properties and on our ability to select and acquire suitable producing properties or prospects. There is no assurance that we will be able to continue to find satisfactory properties to acquire or participate in. Moreover, our management may determine that current markets, terms of acquisition and, participation or pricing conditions make potential acquisitions or participation uneconomic. There is also no assurance that we will discover or acquire further commercial quantities of oil and natural gas.

Future oil and natural gas exploration may involve unprofitable efforts from dry wells as well as from 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, and shut-in wells resulting from extreme weather conditions, insufficient storage or transportation capacity or geological and mechanical conditions. While diligent well supervision and effective maintenance operations 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.

Our production is concentrated in key producing assets.

With the sale of approximately $2.3 billion of assets since 2012, in part to fund the first commercial phase of our Lindbergh Project, our assets have become much less diversified and increasingly concentrated in one project, product type (bitumen) and one area/formation. A significant portion of our current and future production and revenue is generated from our Lindbergh and Groundbirch projects. A failure to execute at Lindbergh or Groundbirch could have a material adverse effect on our business, financial condition and profitability.

There are risks associated with our projects, which can impact the revenue generated from our operations.

There are risks associated with the execution and operation of our growth and development projects. We manage a variety of small and large projects in the conduct of our business. Project delays may delay expected revenues from operations. In addition, significant project cost overruns could make a project uneconomic. Our ability to execute projects and market oil and natural gas depends upon numerous factors beyond our control, including:

- the availability of processing and storage capacity;
- the availability and proximity of pipeline capacity;
- the availability of, and the ability to acquire, water supplies needed for drilling and, hydraulic fracturing, and waterfloods or our 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 supply and demand for crude oil and natural gas;
- fluctuations in the market price of crude oil and natural gas;
- the availability of alternative fuel sources;
- the availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- export taxes;
- changes in regulations and the ability to obtain necessary environmental and regulatory approvals;
- 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.

As a result of these and other factors, we could be unable to execute projects on time, on budget or at all, and may be unable to market the oil and natural gas that we produce effectively.

The operation of a portion of our properties is largely dependent on the ability of third party operators, and harm to their business could cause delays and additional expenses in our receiving revenues, which could negatively affect the market price of the Common Shares.

The continuing production from a property, and to some extent the marketing of production, is dependent upon the ability of the operators of our properties. Approximately eight percent of our properties are operated by third parties, based on daily production. If, in situations where we are not the operator, the operator fails to perform these functions properly or becomes insolvent, revenues may be reduced. Revenues from production generally flow through the operator and, where we are not the operator; there is a risk of delay and additional expense in receiving such revenues.

The operation of the wells located on properties not operated by us are generally governed by operating agreements which typically require the operator to conduct operations in a good and workman-like manner. Operating agreements generally provide, however, that the operator will have no liability to the other non-operating working interest owners for losses sustained or liabilities incurred, except such as may result from gross negligence or willful misconduct. In addition, third-party operators are generally not fiduciaries with respect to us or our Shareholders. As owner of working interests in properties not operated by us, we will generally have a cause of action for damages arising from a breach of the operator's duty. Although not established by definitive legal precedent, it is unlikely that we or our Shareholders would be entitled to bring suit against third party operators to enforce the terms of the operating agreements. Therefore, our Shareholders will be dependent upon us, as owner of the working interest, to enforce such rights.

In addition, due to the current low and volatile commodity prices, many companies, including companies that may operate some of the assets in which we have 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 we have an interest fail to satisfy regulatory requirements with respect to abandonment and reclamation obligations we may be required to satisfy such obligations and to seek reimbursement 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, us potentially becoming subject to additional liabilities relating to such assets and us having difficulty collecting revenue due from such operators or recovering amounts owing to us from such operators for their share of abandonment and reclamation obligations. Any of these factors could materially adversely affect our financial and operational results.

Lower oil and gas prices increase the risk of write-downs of our oil and gas property investments which could be viewed unfavourably in the market or could limit our ability to borrow funds or comply with covenants contained in our current or future credit agreements or other debt instruments.

Under Canadian accounting rules, the net capitalized cost of oil and gas properties may not exceed a "ceiling limit" which is based, in part, upon estimated future net cash flows from reserves. If the net capitalized costs exceed this limit, we must charge the amount of the excess against earnings. As oil and gas prices and engineering price decks decline, our net capitalized cost may approach and, in certain circumstances, exceed this cost ceiling, resulting in a charge against earnings. Under United States accounting rules, the cost ceiling is generally lower than under Canadian rules because the future net cash flows used in the United States ceiling test are based on proved reserves only. Accordingly, we would have more risk of a ceiling test write-down in a declining price environment if we reported under United States generally accepted accounting principles. While these write-downs would not affect cash flow, the charge to earnings could be viewed unfavourably in the market or could limit our ability to borrow funds or comply with covenants contained in our current or future credit agreements or other debt instruments.

Future acquisitions or financing activities may result in dilution of your Common Share holdings.

One of our objectives is to continually add to our reserves through acquisitions and through development. Our success is, in part, dependent on our ability to raise capital from time to time. We cannot predict the size of future issuances of Common Shares or the issuance of debt instruments or other securities convertible into Common Shares or the effect, if any, that future issuances and sales of securities will have on the market price of the Common Shares. In addition, acquisitions, financings or other transactions involving the issuance of securities may be dilutive to the current holders of Common Shares. There are no restrictions in our articles or by-laws with respect to the number of Common Shares that may be issued and outstanding.

Delays in business operations could adversely affect the market price of the Common Shares.

In addition to the usual delays in payment by purchasers of oil and natural gas to the operators of our properties, and the delays of those operators in remitting payment to us, payments between any of these parties may also be delayed by:

- restrictions imposed by lenders;
- accounting delays;
- delays in the sale or delivery of products;
- delays in the connection of wells to a gathering system;
- blowouts or other accidents;
- adjustments for prior periods;
- recovery by the operator of expenses incurred in the operation of the properties; or
- the establishment by the operator of reserves for these expenses.

Any of these delays could reduce the amount of cash available for dividend to Shareholders in a given period and expose us to additional third party credit risks.

Changes in market-based factors may adversely affect the trading price of the Common Shares.

The market price of our Common Shares is sensitive to a variety of market based factors including, but not limited to, interest rates, foreign exchange rates and the comparability of the Common Shares to other yield-oriented securities. Any changes in these market-based factors may adversely affect the trading price of the Common Shares. In addition, in certain jurisdictions institutions, including government sponsored entities, have determined to decrease their ownership in oil and gas entities which may impact the liquidity of certain securities and may put downward pressure on the trading price of those securities.

Lindbergh Thermal Project Specific Risks.

Continued expansion of our Lindbergh thermal project will require substantial capital investment over the coming years. As discussed above, during June, 2018, we announced our Multi-Year Development Plan which provides for a more incremental growth strategy that is aligned with Pengrowth's expected cash flow. In addition to the risk factors set out above, there are certain additional risk factors associated with the development of our Lindbergh thermal project. These include the following:

Ability to Fund Development

The capital to be committed to our Lindbergh thermal project during 2019 and onwards will be dependent on the prevailing price of oil, and as such, our ability to fund further development will be impacted by fluctuations in the price of oil. At a WTI price of US$65 per bbl, capital spending is expected to increase to a range of $120 to $125 million in 2019 and be fully funded with generated cash flows. Pengrowth expects to generate free cash flow under this scenario which will be used to pay down debt. If the price of oil is less than WTI US$65 per bbl, Pengrowth may not be in a position to continue capital development activities while also paying down debt with generated free cash flows. See also "Operational Risks - Low oil and natural gas prices could have a material adverse effect on our results of operations and financial condition, which, in turn, could negatively affect the market price of the Common Shares."

With our expansion spending tied to cash flow generation, there is a risk that we will be unable to generate sufficient cash flow to support our planned growth activities. If this scenario is to arise, Pengrowth may look at other options to expand the Lindbergh project through smaller, less capital-intensive expansion options with the most favourable economics that resource exploitation planning and facility design will allow, or Pengrowth may explore additional financing opportunities. The inability of Pengrowth to access sufficient capital for its operations could materially adversely affect our financial condition.

Any expansion phases of the Lindbergh thermal project are not anticipated to be constructed on a turn-key basis. Additionally, given the state of development of the Lindbergh thermal project, various changes to the project may be made. The information contained herein related to the Lindbergh thermal project, including, without limitation, reserve and economic evaluations, assumes no material changes being made to the project or its scope.

Should expansion phases of the Lindbergh thermal project be sanctioned by our Board, it is anticipated that the industry could also be in a period of substantial oil sands development and industrial activity. We will need to compete for equipment, supplies, services, and labour in this environment which could result in increased costs, shortages of goods and services that delay progress, or both. Increased competition for equipment, materials and labour may result in increased costs that could have a material adverse effect on our business, financial condition or results of operations. As such, there are risks associated with project cost estimates provided by us. Cost estimates are provided prior to engineering being 100% complete. The final scope, design and detailed engineering are required to reduce the margin of error. Accordingly, actual costs may vary from estimates and these differences may be material.

Operating Costs

The operating costs of the Lindbergh thermal project have the potential to vary considerably throughout the operating period and will be significant components of the cost of production of any petroleum products produced by the Lindbergh thermal project. Project economics and our overall earnings may be reduced if increases in operating costs are incurred. Factors which could affect operating costs include, without limitation;

- the amount and cost of labour to operate the Lindbergh thermal project;
- the cost of catalyst and chemicals;
- the actual steam oil ratio required to operate the SAGD well pairs;
- the cost of natural gas and electricity;
- power outages, particularly in winter when freeze-ups could occur;
- produced sand causing issues of erosion, hot spots and corrosion;
- reliability of the facilities;
- the maintenance cost of the facilities;
- the availability of transportation alternatives;
- the cost to transport sales products and the cost to dispose of certain by-products;
- the cost of well maintenance and workovers as a result of decreased productivity;

- the cost of insurance; and
- catastrophic events such as fires, earthquakes, storms or explosions.

Operational Hazards and Infrastructure for the Lindbergh Thermal Project

We depend, to a large extent, on third party designers, contractors and suppliers to design and construct the necessary facilities and infrastructure for any expansion of the Lindbergh thermal project. We rely on certain infrastructure owned and operated or to be constructed by others, including, without limitation, pipelines for the transportation of diluent and produced bitumen to the market, natural gas, water source and disposal pipelines and electrical grid transmission lines for the provision and/or sale of electricity to us. The failure of any or all of these third parties to supply utilities, services or construct the infrastructure required for the Lindbergh thermal project would negatively impact our operation and financial results. See also "Operational Risks - The amount of oil and natural gas that we can produce and sell is subject to the accessibility, availability, proximity and capacity of gathering, processing and pipeline systems."

In addition, equipment failures could result in damage to the project facilities and liability to third parties against which we may not be able to fully insure or may elect not to insure because of costs or for other reasons.

In-situ Extraction

Current SAGD technologies for in-situ recovery of heavy crude oil and bitumen are energy intensive, requiring significant consumption of natural gas and other fuels in the production of steam which is used in the recovery process. The amount of steam required in the production process can also vary and significantly impact costs. The performance of the reservoir can also impact the timing and levels of production using this technology.

Pengrowth expects to implement the use of Non-Condensable Gas ("NCG") injection and solvents with the hope of enhancing production while lowering the steam requirements for the project. While the implementation of NCG, in tandem with infill wells, is expected to improve operating efficiencies, reduce steam requirements and reduce water use and emissions, there is no certainty that these results will occur. There are additional costs associated with implementing the use of NCG injection and solvents, and there is no certainty that these actions will enhance production while reducing associated costs.

Recovery of Bitumen

Recovering bitumen from oil sands involves particular risks and uncertainties. SAGD bitumen recovery facilities and development and expansion of production can entail significant capital outlays. SAGD projects like Lindbergh are susceptible to loss of production, slowdowns, or restrictions on their ability to produce higher value products due to the interdependence of component systems. Severe weather conditions can cause reduced production and in some situations result in higher costs.

Access to Diluent Supplies at Favourable Prices

Bitumen is characterized by high specific gravity or weight and high viscosity or resistance to flow. Diluent, a hydrocarbon based diluting agent, is required to facilitate the transportation of bitumen. A shortfall in the supply of diluent may cause its price to increase thereby increasing the cost to transport bitumen to market and correspondingly increasing our operating costs, decreasing our net revenues and negatively impacting the overall profitability of the Lindbergh thermal project.

Marketing of Production

The market prices for heavy crude oil (which includes bitumen blends) are lower than the established market indices for light or medium grades of oil, due principally to diluent prices and the higher transportation and refining costs associated with heavy crude oil. Also, the market for heavy crude oil is more limited than for light and medium grades of oil, making it more susceptible to supply and demand fundamentals. Future price differentials are uncertain and any increase in heavy crude oil differentials could have an adverse effect on the anticipated returns from the Lindbergh thermal project as well as our overall business, financial condition, results of operations and cash flows.

Regulatory Approvals

Throughout the life of the Lindbergh Project, various regulatory approvals may be required. These included, but are not limited to, scheme amendments, EPEA and Water Act (Alberta) approval amendments. Pengrowth submitted a scheme amendment and an EPEA update in February 2017, to increase the maximum oil rate of the Lindbergh thermal project to 40,000 bbl/day. This approval was received on August 1, 2017. In early 2018, Pengrowth filed an application with the AER for the use of NCG injection at Lindbergh and received approval in early June 2018.

When going through any regulatory review process, the risk areas include but are not limited to; the regulators' ability to review the application and associated supplemental information requests, third party reviews on behalf of the regulator taking longer than anticipated, statements of concern submitted by industry operators, land owners, grazing lease holders, municipalities and First Nation and Métis groups in the region as well as technical or environmental issues identified in the submission in regard to surface infrastructure, subsurface reservoir, cap rock, surface or subsurface water, etc. Addressing these issues or concerns may take a significant amount of time and involve associated costs in order to meet the regulators' requirements, often leading to delays in the approval process. Unresolved statements of concern may require a hearing with the regulators which may or may not be resolved in favor of Pengrowth and, if resolved via a hearing, will also add delays and cost to the timing of approvals, which can have a negative impact on the results of our financial operations.

Our success depends in large measure on certain key and qualified personnel.

Our success depends on attraction and retention of certain key personnel. Failure to retain critical talent or to attract and retain new talent with the necessary leadership traits, skills and competencies could have a material adverse effect on our results of operations, pace of growth and financial condition. The contributions of the existing management team to our immediate and near term operations 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 we will be able to continue to attract and retain all personnel necessary for the development and operation of our business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of our management.

We may be unable to successfully compete with other industry participants, which could negatively affect the market price of the Common Shares.

The petroleum industry is competitive in all its phases. We compete with numerous other entities in the search for, and the acquisition of, oil and natural gas properties, the marketing of oil and natural gas, hiring the equipment and expertise required to safely and cost-effectively develop resources, and constructing and transporting resources. Our competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than us. The petroleum industry also competes with other industries in supplying energy, fuel and related products to customers. Key success factors in each of these markets include price, methods, product quality, logistics and reliability of delivery and storage.

Our ability to compete in the future will depend on, among other things, our ability to increase our reserves through the exploration and development of our present properties as well as through selection and acquisition of suitable producing properties or prospects for exploratory drilling.

We may become involved in, named a as a party to, or be the subject of, various legal proceedings including regulatory proceedings, tax proceedings and legal actions, related to personal injuries, property damage, property tax, land rights, the environment and contract disputes.

In the normal course of our activities, we may become involved in, named as a party to, or be the subject of various legal proceedings, including regulatory proceedings, tax proceedings or legal actions related to personal injury, property damage, property tax, land rights, the environment or lease and contract disputes, among other potential claims. Claims under such proceedings may be material or may be indeterminate. The outcome of outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to us and as a result, could have a material adverse effect on our assets, liabilities, business, financial condition and results of operations.

Financial Risks

Failure to comply with the covenants in the agreements governing our debt could adversely affect our financial condition.

We are required to comply with the covenants in our Credit Facility and the Term Notes. We have negotiated a period of covenant relaxation with the holders of our Term Notes and lenders under our Credit Facility which relaxation period applies, in the case of our Credit Facility, until expiry on March 31, 2019 and, in the case of our Term Notes, through to and including the quarter ended September 30, 2019. At the expiry of these extensions, we will need to negotiate further extensions with our lenders, or otherwise comply with the covenants in our Credit Facility and the Term Notes. A failure to comply with covenants could result in a default under the Credit Facility and Term Notes, which could result in us being required to repay amounts owing thereunder. The acceleration of indebtedness under one agreement may permit acceleration of indebtedness under other agreements that contain cross default or cross-acceleration provisions.

Furthermore, if we are unable to pay the debt service charges or otherwise commit an event of default, such as bankruptcy, our lenders may receive judgment and have an unsecured claim on our properties. The proceeds of any sale would be applied to satisfy amounts owed to the creditors. Only after the proceeds of that sale were applied towards the debt would the remainder, if any, be available for the benefit of our Shareholders. If we grant our creditors security over our assets, non-payment of debt service charges or other default could result in the seizure of our assets by the secured creditors.

Our Credit Facility may not provide sufficient liquidity and a failure to renew our Credit Facility or source alternative funding could adversely affect our financial condition.

Our existing Credit Facility and any replacement credit facility may not provide sufficient liquidity. The amounts available under our existing Credit Facility may not be sufficient for future operations, or we may not be able to obtain additional financing on economic terms attractive to us, if at all. There can be no assurance that the amount of our Credit Facility will be adequate for our future financial obligations, including our future capital expenditure program, or that we will be able to obtain additional funds. In the event we are unable to refinance our debt obligations, it may impact our ability to fund our ongoing operations. In the event that the Credit Facility is not extended before March 31, 2019, indebtedness under the Credit Facility will be repayable at that time. In addition, we are required to repay the Term Notes on maturity. There is also a risk that the Credit Facility will not be renewed for the same amount or on the same terms.

If we are unable to repay amounts owing under our Credit Facility, our lenders could proceed to foreclose or otherwise realize upon the collateral granted to them to secure the indebtedness. In addition, the Credit Facility and other credit arrangements may impose operating and financial restrictions on us that could include restrictions on the payment of dividends, the repurchase or making of other distributions with respect to our securities, incurring of additional indebtedness, the provision of guarantees, the assumption of loans, making of capital expenditures, entering into of amalgamations, mergers, take-over bids or disposition of assets, among other restrictions. The imposition of restrictions in respect of our credit arrangements could have a material adverse effect on the results of our operations and our financial condition.

Our level of indebtedness from time to time could impair our ability to obtain additional financing on a timely basis, or at all, to take advantage of business opportunities that may arise.

Our debt and other financial commitments may limit our financial and operating flexibility.

As of December 31, 2018 our long-term debt was approximately $714.6 million. We also have commitments under leases, operational contracts, transportation and storage contracts, and purchase obligations for services and products. Our debt levels and financial commitments could have significant and adverse consequences to our business, including:

- an increased sensitivity to adverse economic and industry conditions;
- a limited ability to fund future working capital and capital expenditures, engage in future acquisitions or development activities, or to otherwise fully realize the value of assets or opportunities, because a substantial portion of our cash flows are required to service debt and other obligations;
- a limited ability to plan for, or react to, industry trends; and
- an uncompetitive position relative to our competitors whose debt and financial commitment levels are lower.

In the normal course of our business, we have entered into contractual arrangements with third parties that subject us to the risk that such parties may default on their obligations.

We are exposed to third party credit risk through our contractual arrangements with current or future joint venture partners, marketers of our petroleum and natural gas production and other parties. In the event such entities fail to meet their contractual obligations to us, such failures could have a material adverse effect on our business, financial condition, results of operations and prospects. In addition, poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in our ongoing capital program, potentially delaying the program and the results of such program until we find a suitable alternative partner. If any such third parties go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency, it could result in Pengrowth being unable to collect all or a portion of any money owing from such parties. Any of these factors could have a material adverse effect on our business, financial condition, results of operations and prospects.

Fluctuations in foreign currency exchange rates and interest rates could adversely affect our business and the market price of the Common Shares.

Global oil and natural gas prices are quoted in United States dollars. The Canadian/United States dollar exchange rate fluctuates over time and as a consequence, affects the price received by Canadian producers of oil and natural gas, including Pengrowth. Material increases in the value of the Canadian dollar relative to the United States dollar will negatively affect our production revenues, and could affect the future value of our reserves as determined by independent evaluators.

Pengrowth has substantial exposure to the US dollar. Any decrease in the value of the Canadian dollar relative to the US dollar results in an increase in the Canadian dollar equivalent of Pengrowth's US dollar denominated term debt as Pengrowth reports and prepares its covenant calculations in Canadian dollars. A significant decrease in the value of the Canadian dollar relative to the US dollar could cause Pengrowth to be in violation of its debt covenants resulting in Pengrowth being in default of its debt obligations.

To the extent that we engage in risk management activities related to foreign exchange rates, there is a credit risk associated with counterparties with which we may contract.

An increase in interest rates could result in a significant increase in the amount we pay to service debt, resulting in a reduced amount available to fund our exploration and development activities and could negatively impact the market price of our Common Shares.

We engage in hedging activities which could limit the full benefit of commodity price increases.

From time to time we enter into agreements to receive fixed prices for our oil and natural gas production to offset the risk of revenue losses if commodity prices decline. However, to the extent that we engage in price risk management activities to protect ourselves from commodity price declines, we 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, our hedging arrangements may expose us to the risk of financial loss in certain circumstances, including instances in which:

- production falls short of the hedged volumes or Pengrowth fails to fulfill its obligations related to the underlying physical transaction;
- 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; or
- a sudden unexpected event materially impacts oil and natural gas prices.

From time to time we may also enter into agreements to fix the exchange rate of Canadian to United States dollars in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the United States dollar. However, if the Canadian dollar declines in value compared to the United States dollar, we will not benefit from the fluctuating exchange rate. In addition, although a low value of the Canadian dollar relative to the United States dollar may positively affect the price we receive for our oil and natural gas production, it could also result in an increase in the price for certain goods used for our operations, which may have a negative impact on our financial results.

Incorrect assessments of value at the time of acquisitions could adversely affect the value of our Common Shares.

Acquisitions of oil and gas properties or companies are based in large part on engineering and economic assessments made by independent engineers. These assessments include a series of assumptions regarding such factors as recoverability and marketability of oil and gas, future prices of oil and gas and 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 our control. All such assessments involve a measure of geologic and engineering uncertainty which could result in lower than anticipated production and reserves.

If we default on our debts, the net proceeds of any foreclosure sale would be allocated to the repayment of our lenders, note holders and other creditors and only the remainder, if any, would be available for distribution to our Shareholders.

Variations in interest rates, exchange rates and scheduled principal repayments could result in significant changes in the amount we are required to apply to the service of our outstanding indebtedness and our ability to service our debt will depend upon, among other things, our future financial and operating performance, which will be affected by prevailing economic, business, market and other conditions, some of which are beyond our control. If our operating and financial results are not sufficient to service current or future indebtedness, Pengrowth may take actions such as reducing or delaying business activities, investments or capital expenditures, selling assets, restructuring or refinancing our debt, or seeking additional equity capital. Furthermore, if we become unable to pay our debt service charges or otherwise cause an event of default to occur, access to our Credit Facility can become restricted and our lenders may foreclose on, or sell, our properties. The net proceeds of any such sale will be allocated firstly to the repayment of our lenders and other creditors and only the remainder, if any, would be payable to Shareholders. In addition, we may not be able to refinance some or all of these debt obligations through the issuance of new debt obligations on the same terms, and we may be required to refinance through the issuance of new debt obligations on less favourable terms or through the issuance of additional securities or through other means.

We are required to comply with covenants under our Credit Facility and Term Notes. Events beyond our control may contribute to our failure to comply with such covenants. Failing a financial covenant may result in access to our Credit Facility becoming restricted and/or one or more of our loans being in default. In certain circumstances, being in default of one loan will, absent a cure, result in other loans also being in default. In the event that non-compliance continued, we would have to repay, refinance or re-negotiate the terms and conditions of the debt.

If any of our lenders require repayment of all or portion of the amounts outstanding under our loans for any reason, including for a default of a covenant, there is no certainty that we would be in a position to make such repayment. Given the current market conditions and the lack of confidence in the Canadian oil and gas industry, we may have difficulty raising additional funds or if it we are able to do so, it may be on unfavourable and highly dilutive terms.

There is a very limited public trading market for our Common Shares in the United States, and the market for our Common Shares in the United States may continue to be limited and be sporadic and highly volatile.

There is currently a limited public market for our Common Shares in the United States. Our Common Shares trade over the counter in the United States on the OTCQX market place. We cannot assure you that an active market for our Common Shares will be established or maintained in the future. The OTCQX is not a national securities exchange, and many companies have experienced limited liquidity when traded through this quotation system. Holders of our Common Shares in the United States may, therefore, have difficulty selling their shares, should they decide to do so. In addition, there can be no assurances that such markets in the United States will continue or that any shares, which may be purchased, may be sold without incurring a loss. The market price of our Common Shares in the United States, from time to time, may not necessarily bear any relationship to our book value, assets, past operating results, financial condition or any other established criteria of value, and may not be indicative of the market price for the shares in the future.

We could be negatively impacted by changes in asset retirement obligations.

We have substantial future asset retirement obligations. There is a risk that the magnitude of these payments may be larger than expected and that the timing of such payments may accelerate. Either of these factors could increase our financial costs.

Regulatory and Political Risks

Changes in royalty regime may have significant impact on oil and gas production profitability.

Both the federal government and the provincial governments have imposed regulation surrounding royalties, production rates and other related matters. In Alberta, the royalty regime is a significant factor in the profitability of oil and natural gas production. If the regulations surrounding royalties were to be modified, it could have an impact on the economics of our projects. An increase in royalties would reduce our earnings and could make future capital investments, or our current production operations, less economic.

Political uncertainty has impacted and continues to impact financial and economic markets.

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. During 2017 and 2018, the United States government took steps to implement and act on certain of the election promises relating to trade and marketability of commodities and tax reform. Among other actions, the United States government withdrew from the Trans-Pacific Partnership and passed sweeping tax reform, which significantly reduced US corporate tax rates. These actions may affect the competitiveness of other jurisdictions, including Canada. In November, 2018, Canada, the United States and Mexico signed the Canada-United States-Mexico Agreement ("**USMCA**") to replace the North American Free Trade Agreement, which the United States government has indicated it will be withdrawing from. There is uncertainty surrounding the ratification of the USMCA, further contributing to general instability around the future of United States-Canada trade. It is unclear exactly what other actions the administration in the United States will take, and how these actions may impact Canada and in particular, the oil and gas industry. Any actions taken by the United States administration may have a negative impact on the Canadian economy and on the businesses, financial conditions, results of operations and the valuation of Canadian oil and gas companies, including Pengrowth.

In addition to the political disruption in the United States, certain European countries have experienced the rise of anti-establishment political parties and public protests held against open-door immigration policies, trade and globalization, and the United Kingdom is working to withdraw from the European Union. 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 our ability to market our products outside of Canada, increase costs for goods and services required for our operations, reduce access to skilled labour and negatively impact our business, operations, financial conditions and ultimately the market value of our Common Shares.

In addition to international factors, a change in the federal, provincial or municipal governments in Canada could have an impact on the Canadian oil and gas industry, as a result of a shift in the balance between economic development and environmental policy, or changes in the royalty or tax regimes. The announcements and actions taken by the government of British Columbia in the last couple of years have had a direct impact on the completion of pipeline projects and pipeline supply.

Changes and uncertainties in the political environment, both inside and outside of Canada, and the interactions between Canada and other nations, may directly impact the ability and feasibility of Pengrowth to export its products from Canada. Potential regulation in the United States favouring nationalism could disincentive or penalize international trade, which could significantly reduce demand for the Corporation's goods and impact the price at which the Corporation can sell its products.

Our operation of oil and natural gas wells could subject us to potential environmental claims and liabilities, which will be funded out of our cash flow and will reduce cash flow otherwise available for dividend to Shareholders.

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 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.

Alberta, Saskatchewan and British Columbia have developed liability management programs designed to prevent taxpayers from incurring costs associated with 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. These programs involve 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 our deemed assets to deemed liabilities or other changes to the requirements of liability management programs may result in significant increases to our compliance obligations. In addition, the liability management regime may prevent or interfere with our ability to acquire or dispose of assets as both the vendor and the purchaser of oil and gas assets must be in compliance with the liability management programs (both before and after the transfer of the assets) for the applicable regulatory agency to allow for the transfer of such assets. See "*Industry Conditions - Regulatory Authorities and Environmental Regulation - Liability Management Rating Program*".

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 us to incur costs to remedy such discharge. Although we believe that we will be in material compliance with current applicable environmental compliance requirements, no assurance can be given that environmental laws 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 our business, financial condition, results of operations and prospects.

Compliance with greenhouse gas emissions regulations may result in increased operational costs.

Our exploration and production facilities and other operations and activities emit greenhouse gases which may require us to comply with greenhouse gas emissions legislation at the provincial or federal level. 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 a signatory to the Paris Agreement, which was ratified in Canada on October 3, 2016, the Government of Canada pledged to cut its GHG emissions by 30 per cent from 2005 levels by 2030. One of the pertinent policies announced to date by the Government of Canada to reduce GHG emission is the planned implementation of a nation-wide price on carbon emissions. 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 direct or indirect costs of compliance with GHG-related regulations may have a material adverse effect on our business, financial condition, results of operations and prospects. Some of our significant facilities may ultimately be subject to future regional, provincial and/or federal climate change regulations to manage GHG emissions.

In addition, 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. 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 our operating expenses and in the long-term reducing the demand for oil and gas production resulting in a decrease in our profitability and a reduction in the value of our assets or asset write-offs. See “Industry Conditions - Regulatory Authorities and Environmental Regulation - Climate Change Regulation”.

Taxes on carbon emissions affect the demand for oil and natural gas, our operating expenses and may impair our ability to compete.

The majority of countries across the globe have agreed to reduce their carbon emissions in accordance with the Paris Agreement. See “*Industry Conditions - Regulatory Authorities and Environmental Regulation - Climate Change Regulation*”. In Canada, the federal and certain provincial governments have implemented legislation aimed at incentivizing the use of alternatives fuels and in turn reducing carbon emissions. 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 our operating expenses, each of which may have a material adverse effect on our profitability and financial condition. Further, the imposition of carbon taxes puts us at a disadvantage with our counterparts who operate in jurisdictions where there are less costly carbon regulations.

Changes in government regulations that affect the crude oil and natural gas industry could adversely affect us.

Various levels of governments impose extensive controls and regulations on oil and natural gas operations (including exploration, development, production, pricing, marketing and transportation). These laws and regulations govern, amongst other things:

- the types and quantities of substances and waste materials that may be discharged into the surface and sub-surface environment;
- the use or removal of natural resources (such as water and timber) in exploration and production activities;
- the release of greenhouse gases, such as carbon dioxide and methane, into the atmosphere;
- the abandonment, reclamation and remediation of worksites (including sites of former operations);
- the issuance of permits and other regulatory approvals in connection with exploration, drilling and production activities, the construction of roads, pipelines and other regional transportation infrastructure; and
- marketing and pricing policies, royalties, various taxes and levies including income tax, and foreign trade and investment.

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 of existing regulations affecting the oil and natural gas industry could reduce demand for crude oil and natural gas and increase our costs, either of which may have a material adverse effect on our business, financial condition, results of operations and prospects. In recent years, the federal government and certain provincial governments have taken steps to initiate protocols and regulations to regulate greenhouse gas emissions. Such draft regulations and protocols may have a material adverse effect on the oil and gas industry, including Pengrowth. See “Industry Conditions - Regulatory Authorities and Environmental Regulation - Climate Change Regulation”.

In order to conduct oil and natural gas operations, we will require regulatory permits, licenses, registrations, approvals and authorizations from various governmental authorities. There can be no assurance that we will be able to obtain all of the permits, licenses, registrations, approvals and authorizations that may be required to conduct operations that we may wish to undertake. In addition, obtaining certain approvals from regulatory authorities can involve, among other things, stakeholder and Aboriginal consultation, environmental impact assessments and public hearings. Regulatory approvals obtained may be subject to the satisfaction of certain conditions including, but not limited to: security deposit obligations; ongoing regulatory oversight of projects; mitigating or avoiding project impacts; habitat assessments; and other commitments or obligations. Furthermore, regulatory requirements pertaining to the production, marketing and sale of oil and natural, our business and financial condition could be influenced by federal legislation affecting, in particular, foreign investment, through legislation such as the Competition Act (Canada) and the Investment Canada Act (Canada).

Failure to obtain applicable regulatory approvals or satisfy any of the conditions thereto on a timely basis on satisfactory terms, or the termination or expiration of applicable licenses, permits and leases, could result in delays, abandonment or restructuring of projects and increased costs. The laws and regulations governing the oil and gas industry may impose significant liabilities on a failure to comply with their requirements, including the possibility of administrative, civil and criminal penalties, cancellation or suspension of permits or authorizations, investigations or other proceedings, which could have a material adverse effect on our operations and financial condition.

Our hydraulic fracturing activities are subject to increasing regulation.

Hydraulic fracturing involves the injection of water, sand and small amounts of additives under pressure into rock formations to stimulate hydrocarbon (oil and natural gas) production. Specifically, hydraulic fracturing is used to produce commercial quantities of oil and natural gas from reservoirs that were previously unproductive.

The proliferation of the use of hydraulic fracturing as a recovery technique employed in oil and natural gas drilling has given rise to increased public scrutiny of its environmental aspects, particularly with respect to its potential impact on local aquifers. We utilize hydraulic fracturing in a significant portion of the light oil wells we drill and complete. We believe that the hydraulic fracturing that we conduct, given the depth and location of the wells and consistent utilization of good oilfield practices, is environmentally sound and would not give rise to similar concerns respecting local aquifers.

Pengrowth anticipates that there will be a trend towards increased regulatory requirements concerning hydraulic fracturing in the future. In 2012, the Canadian Association of Petroleum Producers announced hydraulic fracturing operating practices designed to improve water management and water and fluids reporting for shale gas and tight gas development across Canada.

In Alberta, the AER, has implemented requirements for: (i) electronically reporting fracture fluid data, including service provider, fracture scenario, carrier fluid type, proppant type and additives for wells that have been fractured; (ii) electronically reporting water source data, including source location, source type, diversion permit information and volume for all water used in hydraulic fracturing operations with water quality information required for groundwater sources; and (iii) reporting fluid and water source data in daily reports of operations. On May 21, 2013, the AER issued a directive establishing requirements for: (i) preventing the loss of well integrity at a subject well; (ii) assessing, planning for, and mitigating the risks of interwellbore communication with offset wells; (iii) notifying licensees of at-risk offset wells related to hydraulic fracturing operations; (iv) protecting nonsaline aquifers from hydraulic fracturing operations conducted at depths less than 100 metres below of the base of groundwater protection; and (v) notifying the AER about hydraulic fracturing operations.

Due to recent seismic activity reported in the Fox Creek area of Alberta, the AER announced in February 2015, seismic monitoring and reporting requirements for hydraulic fracturing operators in the Duvernay zone in the Fox Creek area. These requirements include, among others, an assessment of the potential for seismicity prior to operations, the implementation of a response plan to address potential events, and the suspension of operations if a seismic event above a particular threshold occurs. The AER continues to monitor seismic activity around the province and may extend these requirements to other areas of the province if necessary.

The Province of British Columbia requires operators to electronically submit reporting information for all hydraulic fracture stimulations performed after May 1, 2013.

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.

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 our costs of compliance and doing business as well as delay the development of oil and natural gas resources from shale 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 we are ultimately able to produce from our reserves.

Aboriginal peoples have claimed aboriginal title and rights to portions of western Canada.

We are not aware that any claims have been made in respect of our properties and assets; however, if a claim arose and was successful such claim may have a material adverse effect on our business, financial condition, results of operations and prospects.

The requirement to consult with Aboriginal Peoples in respect of oil and gas projects and related infrastructure has increased in recent years. The Canadian federal government and the provincial government in Alberta have made a commitment to renew their relationships with the Aboriginal peoples of Canada. The federal government has stated it fully supports the United Nations Declaration on the Rights of Indigenous Peoples (the "**Declaration**") without qualification and that Canada intends ''nothing less than to adopt and implement the Declaration in accordance with the Canadian Constitution.'' On May 30, 2018 the private member's bill, Bill C-262, An Act to ensure that the laws of Canada are in harmony with the United Nations Declaration on the Rights of Indigenous Peoples, a bill which facilitates the full adoption of the Declaration into Canadian Law, was adopted by the House of Commons. It is It is anticipated that the Bill may become law in 2019. If adopted into Canadian Law, it is unclear how the Declaration will impact Crown's duty to consult with Aboriginal peoples.

We are unable to assess the effect, if any, that any such consultation requirements or adoption of the Declaration into Canadian law may have on our business.

We may incur material costs as a result of compliance with health, safety and environmental laws and regulations which could negatively affect our financial condition and, therefore decrease the market price of the Common Shares.

Compliance with environmental laws and regulations could materially increase our costs. We may incur substantial capital and operating costs to comply with increasingly complex laws and regulations covering the protection of the environment and human health and safety. In particular, we may be required to incur significant costs to comply with legislation and regulations to reduce emissions of greenhouse gases into the air. See "Industry Conditions".

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 and liquid hydrocarbons.

Public support for climate change action and receptivity to alternative or renewable energy technologies has grown in recent years. Governments in Canada and around the world have responded to these shifting societal attitudes by implementing policies and/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 gas products. We cannot predict the impact of changing demand for oil and natural gas products, and any major changes may have a material adverse effect on our business, financial condition, results of operations and cash flows.

Other Risks

The oil industry is characterized by rapid and significant technological advancements and introductions of new products and services utilizing new technologies.

Other oil companies may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before we can. There can be no assurance that we will be able to respond to such competitive pressures and implement such technologies on a timely basis or at an acceptable cost. One or more of the technologies currently utilized by us or implemented in the future may become obsolete. In such case, our business, financial condition and results of operations could be materially adversely affected. If we are unable to utilize the most advanced commercially available technology, our business, financial condition and results of operations could be materially adversely affected.

Changing investor sentiment towards the oil and gas industry may impact our access to, and cost of, capital.

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 gas operations on the environment, concerns of environmental damage relating to spills of petroleum products during transportation and concerns about indigenous rights, have affected certain investors' sentiments towards investing in the oil and 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 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 our 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 us or not investing in us at all. Any reduction in the investor base interested or willing to invest in the oil and gas industry and more specifically, Pengrowth, may result in limiting our access to capital, increasing the cost of capital, and decreasing the price and liquidity of our Common Shares.

Potential conflicts of interest.

Certain of our directors are also, or may in the future be, directors or officers of other oil and gas companies and as such may, in certain circumstances, have a conflict of interest requiring them to disclose such interest and abstain from certain decisions. Conflicts, if any, will be subject to the procedures and remedies of the ABCA which require the director or officer 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 us 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 also "*Conflicts of Interest*".

The market price of the Common Shares could be adversely affected by unforeseen title defects.

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise. Our actual interest in properties may, accordingly, vary from our records. If a title defect does exist, it is possible that we may lose all or a portion of the properties to which the title defect relates, which may have a material adverse effect on our business, financial condition, results of operations and prospects. There may be valid challenges to title, or legislative changes which affect title, to the oil and natural gas properties we control that could impair our activities on them and result in a reduction of the revenue received by us.

We may disclose confidential information relating to our business, operations or affairs while discussing potential business relationships or other transactions with third parties.

Although confidentiality agreements are generally signed by third parties prior to the disclosure of any confidential information, a breach could put us at competitive risk and may cause significant damage to our business. The harm to our 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, we 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.

We file all required income tax returns and we believe that we are in full compliance with the provisions of the Tax Act 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 us, whether by re-characterization of exploration and development expenditures or otherwise, such reassessment may have an impact on current and future taxes payable.

Income tax laws relating to the oil and gas industry, such as the treatment of resource taxation or dividends, are complex and may in the future be changed or interpreted in a manner that adversely affects us. While we think our tax filing positions are appropriate and supportable, tax authorities having jurisdiction over us may disagree with how we calculate our income for tax purposes or could change administrative practices to our detriment.

The level of activity in the Canadian oil and natural gas industry is influenced by seasonal weather patterns.

Weather conditions are difficult to anticipate and cannot be controlled. In these conditions, operations can become difficult or unsafe and can be suspended. Some of our facilities and those that our facilities rely upon (such as pipelines, power, communication and oil field equipment) are vulnerable to these types of extreme weather conditions and may suffer extensive or catastrophic damage as a result. If any such extreme weather were to occur, our ability to operate certain facilities and proceed with exploration or development programs could be seriously or completely impaired or destroyed and could have a material adverse effect on our business, financial condition and results of operations. The insurance we maintain may not be adequate to cover our losses resulting from disasters or other business interruptions.

In addition, wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Roads 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 our production if not otherwise tied-in. Certain oil and natural gas producing areas 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. In addition, extreme cold weather, heavy snowfall and heavy rainfall may restrict our ability to access properties, 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 can rise during cold winter months and hot summer months.

Canadian and United States practices differ in reporting reserves and production and our estimates may not be comparable to those of companies in the United States.

We report our production and reserve quantities in accordance with Canadian practices and specifically in accordance with NI 51-101. These practices are different from the practices used to report production and to estimate reserves in reports and other materials filed with the SEC by companies in the United States.

We incorporate additional information with respect to production and reserves which is either not required to be included or prohibited under rules of the SEC and practices in the United States. We follow the Canadian practice of reporting gross production and reserve volumes; however, we also follow the United States practice of separately reporting these volumes on a net basis (after the deduction of royalties and similar payments). We also follow the Canadian practice of using forecast prices and costs when we estimate our reserves. The SEC permits, but does not require, the disclosure of reserves based on forecast prices and costs.

Reserve information contained herein may include estimates of proved, proved plus probable and possible reserves, as well as resources. The SEC permits, but does not require, the inclusion of estimates of probable and possible reserves in filings made with it by United States oil and gas companies. The SEC does not permit the inclusion of estimates of resources in reports filed with it by United States companies.

We rely on our reputation to continue our operations and to attract and retain investors and employees.

Any environmental damage, loss of life, injury or damage to property caused by our operations could damage our reputation in the areas in which we operate and with our stakeholders. Negative sentiment towards us could result in a lack of willingness of regulatory authorities to grant the necessary licenses or permits for us to operate our business, and resistance from residents in the areas in which we operate. If we develop a reputation of having an unsafe work site, it may impact our ability to attract and retain the necessary skilled employees and consultant to operate our business. Our reputation could be affected by actions and activities of other corporations operating in the oil and gas industry, over which we have no control. In addition, environmental damage, loss of life, injury or damage to property caused by our operations could result in negative investor sentiment towards us, which may result in limiting our access to capital, increasing the cost of capital, and decreasing the price and liquidity of our Common Shares. Any of these events could have a material adverse effect on our business, financial condition and results of operation.

We are dependent on our information technology infrastructure.

We have become increasingly dependent upon the availability, capacity, reliability and security of our information technology infrastructure and our ability to expand and continually update this infrastructure, to conduct daily operations. We depend on various information technology systems to estimate reserve quantities, process and record financial data, manage our land base, analyze seismic information, administer our contracts with our operators and lessees and communicate with employees and third-party partners.

Further, we are subject to a variety of information technology and system risks as a part of our normal course operations, including potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach, and destruction or interruption of our 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 our business activities or our 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 we become a victim to a cyber phishing attack it could result in a loss or theft of our financial resources or critical data and information or could result in a loss of control of our technological infrastructure or financial resources. Further, disruption of critical information technology services, or breaches of information security, could result in material financial loss, regulatory action and sanctions, reputational harm and/or legal liability, which, in turn, could materially adversely affect our business, financial condition or profitability. We apply technical and process controls in line with industry-accepted standards to protect our information assets and systems; however, these controls may not adequately prevent cyber-security breaches. 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 our business, financial condition and results of operations.

We rely on our business resiliency plans.

Failure to develop effective business resiliency plans could disrupt operations and cause financial losses, which could materially adversely affect our business, financial condition or profitability.

We are dependent on the availability of our personnel, office facilities and the proper functioning of our computer and telecommunications systems. While management has implemented a business continuity program, which is reviewed and updated regularly, there can be no assurance that our business will not be interrupted and materially adversely affected during a disaster such as a severe weather event, fire, significant water damage, widespread pandemic, a prolonged loss of electricity or explosion or being collaterally damaged by any of the foregoing occurring to neighbouring businesses. While management believes the business continuity program has been developed to minimize any disruption, there can be no assurance of business continuity in the event that there are disruptions of normal operations. A disaster could materially interrupt business operations and, if the disaster recovery plans prove to be ineffective, it could cause material financial loss, loss of human capital, reputational harm or legal liability, which, in turn, could materially adversely affect our business, financial condition or profitability.

The industry in which we operate exposes us to potential liabilities that may not be covered by insurance.

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, sour gas releases, spills and other environmental hazards. These risks and hazards could result in substantial damage to oil and natural gas wells, production facilities, other property, the environment and personal injury. Particularly, we 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 us.

Oil and natural gas production operations are also subject to all the risks typically associated with such operations, 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 could have a material adverse effect on our business, financial condition, results of operations and prospects.

As is standard industry practice, we are not fully insured against all of these risks, nor are all risks insurable. Although we maintain liability insurance in an amount that we consider consistent with industry practice, liabilities associated with certain risks could exceed policy limits or not be covered. In either event, we could incur significant costs. The payment of uninsured liabilities would reduce the funds available to us and the occurrence of a significant event that we are not fully insured against, or the insolvency of the insurer of such event, could have a material adverse effect on our financial position, results of operations or prospects.

Terrorist attacks and the threat of terrorist attacks may have an adverse impact on us.

The impact that future potential terrorist attacks, regional hostilities or political violence may have on the oil and gas industry, and on our operations in particular, is not known at this time. This uncertainty may affect operations in unpredictable ways. In addition, energy sector participants, including us, are a potential target for terrorists. The possibility that infrastructure facilities may be direct targets of, or indirect casualties of, an act of terror and the implementation of security measures as a precaution against possible terrorist attacks may result in increased cost to our business.

The ability of investors resident in the United States to enforce civil remedies may be negatively affected for a number of reasons.

We are an Alberta corporation. We have our principal places of business in Canada. All of our directors and officers are residents of Canada and all or a substantial portion of our assets and the assets of such persons are located outside of the United States. Consequently, it may be difficult for United States investors to affect service of process within the United States upon us or such persons or to realize in the United States upon judgments of courts of the United States predicated upon civil remedies under the United States federal securities laws, as amended. Investors should not assume that Canadian courts:

- will enforce judgments of United States courts obtained in actions against us or such persons predicated upon the civil liability provisions of the United States federal securities laws or the securities or “blue sky” laws of any state within the United States; or
- will enforce, in original actions, liabilities against us or such persons predicated upon the United States federal securities laws or any such state securities or blue sky laws.

Sufficient internal controls are necessary to provide reliable financial reports and assist in fraud prevention.

Effective internal controls are necessary for us to provide reliable financial reports and to help in preventing fraud. Although we undertake a number of procedures in order to help ensure the reliability of our financial reports, including those imposed on us under Canadian securities laws, we cannot be certain that such measures will ensure that we 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 our results of operations or cause us to fail to meet our reporting obligations. If Pengrowth or our independent auditors discover a material weakness, the disclosure of that fact, even if quickly remedied, could reduce the market’s confidence in our financial statements and harm the trading price of the Common Shares.

Forward-looking statements and information may prove inaccurate.

Shareholders and prospective investors are cautioned not to place undue reliance on our forward-looking statements and information. By its nature, forward-looking statements and information involve numerous assumptions, known and unknown risk 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 related to forward-looking statements and information are found under the heading “*Forward-Looking Statements*” in this AIF.

DESCRIPTION OF CAPITAL STRUCTURE

Our authorized capital consists of an unlimited number of Common Shares and 10,000,000 preferred shares, issuable in series ("**Preferred Shares**"). The following is a summary of the rights, privileges, restrictions and conditions attaching to the securities which comprise our share capital.

Common Shares

Holders of our Common Shares are entitled to notice of, to attend and to one vote per share held at any meeting of our Shareholders (other than meetings of a class or series of our shares other than the Common Shares as such). Holders of our Common Shares will be entitled to receive dividends as and when declared by our Board on our Common Shares as a class, subject to prior satisfaction of all preferential rights to dividends attached to shares of other classes of our shares ranking in priority to the Common Shares in respect of dividends. Holders of our Common Shares will be entitled in the event of any liquidation, dissolution or winding-up of us, whether voluntary or involuntary, or any other distribution of our assets among our Shareholders for the purpose of winding-up our affairs, and subject to prior satisfaction of all preferential rights to return of capital on dissolution attached to all shares of other classes of our shares ranking in priority to the Common Shares in respect of return of capital on dissolution, to share rateably, together with the holders of shares of any other class of our shares ranking equally with the Common Shares in respect of return of capital on dissolution, in such of our assets as are available for distribution.

Preferred Shares

The Preferred Shares may be issued in one or more series, at any time or from time to time. Before any shares of a particular series are issued, our Board will fix the number of shares that will form such series and will, subject to the limitations set out in the preferred share terms described below, fix the designation, rights, privileges, restrictions and conditions to be attached to the Preferred Shares of such series, including, but without in any way limiting or restricting the generality of the foregoing, the rate, amount or method of calculation of dividends thereon, the time and place of payment of dividends, the consideration for and the terms and conditions of any purchase for cancellation, retraction or redemption thereof, conversion or exchange rights (if any), and whether into or for our securities or otherwise, voting rights attached thereto (if any), the terms and conditions of any share purchase or retirement plan or sinking fund, and restrictions on the payment of dividends on any shares other than Preferred Shares or payment in respect of capital on any of our shares or creation or issue of debt or equity securities; the whole subject to filing of Articles of Amendment setting forth a description of such series including the designation, rights, privileges, restrictions and conditions attached to the shares of such series. Notwithstanding the foregoing: (a) our Board may at any time or from time to time change the rights, privileges, restrictions and conditions attached to unissued shares of any series of Preferred Shares; and (b) other than in the case of a failure to declare or pay dividends specified in any series of the Preferred Share, the voting rights attached to the Preferred Shares will be limited to one vote per Preferred Share at any meeting where the Preferred Shares and Common Shares vote together as a single class.

Term Notes and Credit Facility

A full description of our Term Notes and Credit Facility can be found in the notes and Management's Discussion and Analysis accompanying our December 31, 2018 audited financial statements.

Stock Exchange Listings

Our Common Shares are listed and posted for trading on the TSX under the symbol "PGF". Trading in the common shares of Pengrowth on the NYSE under the symbol "PGH" ceased after markets closed on June 1, 2018 after Pengrowth received notice on December 1, 2017 that its share price had fallen below the NYSE's continued listing standard for average closing price of less than US $1.00 over a consecutive 30 trading-day period. Pengrowth shares are now traded over-the-counter in the United States on the OTCQX under the symbol "PGHEF". Our 6.25% series B convertible debentures were listed and posted for trading on the TSX under the symbol "PGF.DB.B" until they matured on March 31, 2017.

Dividends and Distributions

No dividends or distributions have been declared in the three most recently completed fiscal years and we do not intend to declare or pay any cash dividends in the foreseeable future.

Our ability to pay cash dividends to shareholders of the Corporation is prohibited by our Credit Facility and the note purchase agreements relating to our Term Notes, as well as the financial capacity and solvency tests under the ABCA.

MARKET FOR SECURITIES

Trading Price and Volume

Our outstanding Common Shares are listed and posted for trading under the symbol "PGF" on the TSX under the symbol "PGF" and on the OTCQX under the symbol "PGHEF". The price ranges and the volumes traded on the TSX for the year ended December 31, 2018 are as follows:

	TSX		
	($) High	($) Low	Volume
January	1.17	0.95	14,717,386
February	0.99	0.84	6,379,956
March	0.92	0.78	5,968,971
April	1.21	0.77	13,582,263
May	1.15	0.95	12,517,803
June	0.97	0.84	8,913,701
July	1.21	0.90	13,330,436
August	0.96	0.88	7,689,576
September	1.17	0.84	15,404,384
October	1.24	0.86	23,457,995
November	0.94	0.68	10,621,330
December	0.72	0.47	12,773,319

Prior Sales

The following table summarizes the issuances of unlisted securities during the year ended December 31, 2018. These unlisted securities were issued pursuant to the Corporation's compensation plans. For further information please see the Management Information Circular dated May 14, 2018 available on our SEDAR profile.

Date of Issuance	Securities	Number of Common Shares Issued/ Issuable or Aggregate Amount	Price/Exercise Price per Security ($)
June 26, 2018	Restricted Share Units	2,350,491	0.87
June 26, 2018	Options	9,250,947	0.87
September 28, 2018	Options	75,972	1.05
September 28, 2018	Restricted Share Units	120,054	1.09
December 20, 2018	Restricted Share Units	52,044	0.57

Escrowed Securities

The Corporation has no escrowed securities or securities subject to contractual restriction on transfer.

DIRECTORS AND OFFICERS

The name, jurisdiction of residence, position held and principal occupation for the previous five years of each of our directors and officers are set out below:

Name and Jurisdiction of Residence	Position with Pengrowth	Principal Occupation
Kelvin B. Johnston[(1)(2)(3)] Alberta, Canada	Chairman and Director (Director since 2012)	President of Wylander Crude Corp. (a private oil and gas company) and Vice President, Corporate Development of Lakeview Energy Inc. (a private oil and gas company).
Peter Sametz Alberta, Canada	President, Chief Executive Officer and Director (Director since 2018)	President and Chief Executive Officer of Pengrowth; prior thereto President and Chief Executive Officer of Gemini Corporation from March 2016 to November 2017, and prior thereto President and Chief Operating Officer of Connacher Oil and Gas Limited since 2004.
Wayne K. Foo[(2)(3)] Alberta, Canada	Director (Director since 2006)[(4)]	Chair of the Board of Parex Resources Inc. (energy company) since May 11, 2017; prior thereto, Chief Executive Officer of Parex Resources Inc. since January 2015; prior thereto, President and Chief Executive Officer of Parex Resources Inc.
Chandra A. Henry [(1)] Alberta, Canada	Director (Director since 2018)	Chief Financial Officer of WestBlock Inc. (technology company); prior thereto, Director of Finance for GMP Securities LP and prior thereto, Chief Financial Officer of FirstEnergy Capital Corp.
James D. McFarland[(1)(3)] Alberta, Canada	Director (Director since 2010)[(4)]	Corporate Director since December 31, 2017; prior thereto, President, Chief Executive Officer and Director of Valeura Energy Inc. from June 2010 until October 19, 2017 and Chief Executive Officer and Director thereafter until his retirement on December 31, 2017.
A. Terence Poole[(1)] Alberta, Canada	Director (Director since 2005)[(4)]	Business Consultant and Corporate Director.
D. Michael G. Stewart[(2)] Alberta, Canada	Director (Director since 2006)[(4)]	Corporate Director.
Randall S. Steele Alberta, Canada	Chief Operating Officer	Chief Operating Officer of Pengrowth since January 2018; prior thereto, Senior Vice President, Conventional Operations of Pengrowth since May 2015 and prior thereto, General Manager, Conventional Operations of Pengrowth since 2013.
Christopher G. Webster Alberta, Canada	Chief Financial Officer	Chief Financial Officer of Pengrowth.

Notes:

(1) Member of the Audit Committee.

(2) Member of Compensation, Corporate Governance and Nominating Committee.

(3) Member of Reserves, Health, Safety and Environment Committee.

(4) Denotes year first appointed as a director of Pengrowth Corporation, a predecessor of ours.

As at December 31, 2018, the foregoing directors and officers, as a group, beneficially owned, directly or indirectly, 3,837,596 Common Shares or approximately 0.69% of the issued and outstanding Common Shares and held rights and options to acquire a further 9,021,464 Common Shares (assuming 100% vesting of all performance-based rights). The information as to shares beneficially owned, not being within our knowledge, has been furnished by the respective individuals.

The term of office for each director expires at the next annual meeting of Shareholders.

Corporate Cease Trade Orders, Bankruptcies, Personal Bankruptcies, Penalties or Sanctions

No director or executive officer is as at the date hereof, or has been within ten years of the date hereof, a director or chief executive officer or chief financial officer of any company, including us, that:

(a) while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer was the subject of a cease trade or similar order or an order that denied the relevant company access to any exemption under securities legislation, for a period of more than 30 consecutive days; or

(b) was subject to a cease trade or similar order, or an order that denied the relevant company access to any exemption under securities legislation, for a period of more than 30 consecutive days, 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.

Other than as set out below, no current director or executive officer or securityholder holding a sufficient number of our securities to affect materially our control is, as of the date hereof, or has been, within the last ten years prior to the date hereof, a director or executive officer of any company (including us) that, while such person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets.

In addition, no current director or executive officer or securityholder holding a sufficient number of our securities to affect materially our control has, within the last ten years prior to the date hereof, 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, officer or securityholder.

No current director or executive officer or securityholder holding a sufficient number of our securities to affect materially control of us 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.

AUDIT AND RISK COMMITTEE

The Audit and Risk Committee is appointed annually by our Board of Directors. The responsibilities and duties of the Audit and Risk Committee are set forth in the Audit and Risk Committee Terms of Reference attached hereto as Appendix D. The following table sets forth the name of each of the current members of our Audit and Risk Committee, whether such member is independent and financially literate, as those terms are defined in National Instrument 52-110 *Audit Committees*, and the relevant education and experience of each member:

Name	Independent	Financially Literate	Relevant Education and Experience
A. Terence Poole (1)	Yes	Yes	Mr. Poole brings extensive senior financial management, accounting, capital and debt market experience to Pengrowth. He retired from Nova Chemicals Corporation in 2006 where he had held various senior management positions including Executive Vice President, Corporate Strategy and Development. Mr. Poole served on the board of directors for Methanex Corporation. Mr. Poole received a Bachelor of Commerce degree from Dalhousie University and holds a Chartered Professional Accountant designation.
Kelvin B. Johnston	Yes	Yes	Mr. Johnston is an executive with more than 35 years' experience in the oil and gas industry. Mr. Johnston serves as President of Wylander Crude Corp., a private oil and gas company, a position he has held since July 2006, and as Vice President, Corporate Development of Lakeview Energy Inc., a private oil and gas company, a position held since June 2009. He is currently a managing director of JOG Capital Corp., a provider of private equity to Canadian junior exploration and production companies. Mr. Johnston serves as director of Leucrotta Exploration Inc., and is a member of the Board of Governors of the Explorers and Producers Assocation of Canada (EPAC).Prior positions include serving as President and Chief Executive Officer of Alberta Clipper Energy Inc., Vice-President, Exploration of Thunder Energy Ltd., and various senior technical, executive and board capacities at Husky Oil Ltd., Startech Energy Inc., Impact Energy Inc., Mustang Resources Ltd. and Peerless Energy Inc. Mr. Johnston holds a Bachelor of Science (Hons) degree in Geology from the University of Manitoba and a Master's degree in Economics from the University of Calgary.
James D. McFarland	Yes	Yes	Mr. McFarland has more than 46 years' experience in the oil and gas industry, most recently as a co-founder, director and retired President and Chief Executive Officer of Valeura Energy Inc., a TSX listed issuer. Prior thereto Mr. McFarland was a co-founder, director and President and Chief Executive Officer of Verenex Energy Inc., a TSX listed issuer. He has served in senior executive roles as Managing Director of Southern Pacific Petroleum N.L. in Australia (an Australian Securities Exchange listed issuer), President and Chief Operating Officer of Husky Oil Limited (a TSX listed issuer) and in a wide range of upstream and corporate functions in an earlier 23-year career with Imperial Oil Limited and other ExxonMobil affiliates in Canada, the US and western Europe. Mr. McFarland currently serves as a director of MEG Energy Corp., Valeura Energy Inc. and Arrow Exploration Corp., and is a past director of Aventura Energy Inc., Vermilion Energy Trust and Vermilion Resources Ltd. (all TSX-listed issuers). Mr. McFarland is a member of the Association of Professional Engineers and Geoscientists of Alberta, the Society of Petroleum Engineers International, the Program Committee of the World Petroleum Council and the Institute of Corporate Directors. He is also a past member of the Australian Institute of Company Directors. Mr. McFarland received a Bachelor of Science in Chemical Engineering from Queen's University and a Master of Science in Petroleum Engineering from the University of Alberta.
Chandra A. Henry	Yes	Yes	Ms. Henry is Chief Financial Officer at WestBlock Inc. Prior thereto Ms. Henry held various senior finance positions including Director of Finance for GMP Securities LP (2016-17) and Chief Financial Officer for FirstEnergy Capital Corp (2001-16). Both firms are leading boutique investment dealers that have served the oil and gas industry for many decades. Ms. Henry has also served as a Director, Treasurer and Chair of the Audit Committee of the Alberta Ballet Company from 2012 to 2018. Ms. Henry has a Bachelor of Commerce degree from the Haskayne School of Business and is both a Chartered Professional Accountant (CPA, CA), a Chartered Financial Analyst Charterholder and is a member of the Institute of Corporate Directors.

Note:

(1) Chair of the Audit Committee.

Reliance on Certain Exemptions

At no time since the commencement of the Corporation's most recently completed financial year has the Corporation relied on any exemption from NI 52-110, including Section 2.4 of NI 52-110 (De Minimis Non-Audit Services), or an exemption granted under Part 8 of NI 52-110.

Audit Committee Oversight

At no time since the commencement of our financial year ended December 31, 2018 was a recommendation of the Audit Committee to nominate or compensate an external auditor not adopted by the Board of Directors.

External Auditor Fees and Services

The following table provides information about the aggregate fees billed to us for professional services rendered by KPMG LLP during fiscal 2018 and 2017:

	2018 ($thousands)	2017 ($thousands)
Audit Fees	776	900
Audit Related Fees	-	-
Tax Compliance and Preparation Services	40	23
Other Tax Services		23
All Other Fees	75	105
Total	**891**	**1,051**

Audit Fees

Audit fees consist of fees for the audit of our annual financial statements and services that are normally provided in connection with statutory and regulatory filings or engagements.

Audit-Related Fees

Audit-related fees include fees billed for assurance and related services that are reasonably related to the performance of the audit or review of our financial statements and are not reported as “Audit Fees”. The services provided in this category normally include due diligence reviews in connection with acquisitions, research of accounting and audit-related issues and the completion of audits required by contracts to which we are a party.

Tax Fees

During 2017 and 2018 the services provided in this category included assistance and advice in relation to the preparation of income tax returns for us and our subsidiaries, tax advice and planning and commodity tax consultation.

All Other Fees

During 2017 and 2018 the services provided in this category relate to translation of financial statements, management's discussion and analysis and other regulatory filings into French.

Pre-Approval Policies and Procedures

Pengrowth has adopted the following policies and procedures with respect to the pre-approval of audit and permitted non-audit services to be provided by KPMG LLP. The Audit and Risk Committee approves a schedule which summarizes the services to be provided that the Audit and Risk Committee believes to be typical, recurring or otherwise likely to be provided by KPMG LLP. The schedule generally covers the period between the adoption of the schedule and the end of the year, but at the option of the Audit and Risk Committee, may cover a shorter or longer period. The list of services is sufficiently detailed as to the particular services to be provided to ensure that: (i) the Audit and Risk Committee knows precisely what services it is being asked to pre-approve; and (ii) it is not necessary for any member of Pengrowth's management to make a judgment as to whether a proposed service fits within the pre-approved services. Services that arise that were not contemplated in the schedule must be pre-approved by the Audit and Risk Committee chairman or a delegate of the Audit and Risk Committee. The full Audit and Risk Committee is informed of the services at its next meeting.

Pengrowth has not approved any non-audit services on the basis of the *de minimis* exemptions. All non-audit services are pre-approved by the Audit and Risk Committee in accordance with the pre-approval policy referenced herein.

CONFLICTS OF INTEREST

Our Board of Directors supervises the management of our business and affairs. The Board of Directors approves significant strategic operational decisions and all decisions relating to:

- the issuance of additional Common Shares;
- material acquisitions and dispositions of properties;
- material capital expenditures;
- borrowing; and
- the payment of dividends.

Circumstances may arise where members of our Board of Directors serve as directors or officers of corporations which are in competition to our interests. The Board of Directors reviews potential conflicts of interest at each meeting. No assurances can be given that opportunities identified by such board members will be provided to us. In addition, some members of our senior management team sit as directors of other corporations. Any such positions must be disclosed to the Board of Directors and approved by the Chief Executive Officer.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

We are sometimes named as a defendant in litigation. The nature of these claims is usually related to settlement of normal operational or labour issues. The outcome of such claims against us are not determinable at this time, however they are not expected to have a materially adverse effect on us as a whole. We are not, and have not been at any time within the most recently completed financial year, a party to any legal proceedings, known or contemplated, where the damages involved, excluding interest and costs, exceed 10% of our assets.

In addition, there have not been any (a) penalties or sanctions imposed against the Corporation by a court relating to securities legislation or by a securities regulatory authority during the year ended December 31, 2018, (b) any 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, or (c) settlement agreements entered into by the Corporation before a court relating to securities legislation or with a securities regulatory authority during the year ended December 31, 2018.

See "*Risk Factors - Operational Risks - We may become involved in, named a as a party to, or be the subject of, various legal proceedings including regulatory proceedings, tax proceedings and legal actions, related to personal injuries, property damage, property tax, land rights, the environment and contract disputes*".

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Other than as discussed herein, there are no material interests, direct or indirect, of any of our directors, executive officers, senior officers, any direct or indirect Shareholder who beneficially owns, or who exercises control over, more than ten percent of our outstanding Common Shares or any known associate or affiliate of such persons, 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 us.

INTERESTS OF EXPERTS

As of the date hereof, the directors and officers of GLJ, as a group, beneficially own, directly or indirectly, less than one percent of the outstanding Common Shares.

KPMG LLP are our auditors and have confirmed that they are independent with respect to us within the meaning of the relevant rules and related interpretations prescribed by the relevant professional bodies in Canada and any applicable legislation or regulations and also that they are independent accountants with respect to us under all relevant US professional and regulatory standards.

AUDITORS, TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for the Common Shares is Computershare Trust Company of Canada at its principal office in the City of Toronto, Ontario. Our auditors are KPMG LLP, Chartered Professional Accountants in Calgary, Alberta.

MATERIAL CONTRACTS

The only material contracts entered into by us during the most recently completed financial year, or before the most recently completed financial year and still in effect, other than during the ordinary course of business, are as follows:

(i) the Credit Facility;

(ii) the Note Purchase Agreement dated October 18, 2012, as amended, concerning the 2012 Senior Notes; and

(iii) the Note Purchase Agreement dated May 11, 2010, as amended, concerning the 2010 Senior Notes.

Copies of these contracts and the relevant amendments have been filed by us on SEDAR and are available through the SEDAR website at www.sedar.com.

OFF-BALANCE SHEET ARRANGEMENTS

Pengrowth has no off-balance sheet arrangements.

CORPORATE GOVERNANCE PRACTICES

As a Canadian reporting issuer with securities listed on the TSX , Pengrowth has in place a system of corporate governance practices which complies with Canadian securities laws and the TSX corporate governance guidelines. Pengrowth qualifies as a foreign private issuer under SEC rules and benchmarks its policies and procedures against major North American entities, with a view to adopting the best practices when appropriate to its circumstances.

The Board of Directors of the Corporation has adopted and published a Corporate Governance Policy which affirms Pengrowth's commitment to maintaining a high standard of corporate governance. This policy is published on Pengrowth's website at www.pengrowth.com. The Board of Directors of the Corporation has also adopted Terms of Reference for each of the Audit and Risk Committee, the Corporate Governance and Nominating Committee, the Compensation Committee, and the Reserves, Health, Safety and Environment Committee, as well as a Code of Business Conduct and Ethics, a Corporate Disclosure Policy and a Policy on Trading in Securities, each of which is published on Pengrowth's website, and is available in print to any Shareholder who requests it. The Audit and Risk Committee's Terms of Reference are attached hereto as Appendix D. From time to time, special committees of the Board of Directors are formed with prescribed mandates.

ADDITIONAL INFORMATION

Additional information, including directors' and officers' remuneration and indebtedness, the principal holders of Common Shares and securities authorized for issuance under equity compensation plans, is contained in our Management Information Circular for our most recent annual meeting of shareholders that involved the election of directors and can be obtained upon request of Pengrowth at the contact information below. Additional financial information is contained in our comparative consolidated financial statements and associated management's discussion and analysis for the years ended December 31, 2018, 2017 and 2016.

Additional information relating to us may be found on SEDAR at www.sedar.com and on EDGAR at the SEC's website at www.sec.gov.

For additional copies of the AIF and the materials listed in the preceding paragraphs please contact:

Investor Relations
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APPENDIX A

SUPPLEMENTAL DISCLOSURE - CONTINGENT RESOURCES

The Corporation has engaged GLJ to prepare Contingent Resource evaluations of its Lindbergh, Selina and Groundbirch properties. The following is a brief description of these properties and a summary of those evaluations.

Lindbergh Oil Sands Reserves and Contingent Resources

The Lindbergh property is described above under *"Principal Producing Properties - Lindbergh"*.

Proved Reserves, Probable Reserves and Possible Reserves have been assigned within the approved Phase 1 and Phase 2 project area. Furthermore, there are Contingent Resources for the area beyond the reserves. GLJ has updated its evaluation of the reserves and Contingent Resources for Lindbergh as of December 31, 2018. The evaluation was limited to portions of the reservoir amenable to SAGD. The profitability of the commercial project will be sensitive to oil prices and reservoir quality.

The tables below summarize the estimated volumes and net present value of Future Net Revenue for Pengrowth's Company Interest reserves and Contingent Resources attributable to the Lindbergh property based upon forecast prices and costs. Contingent Resources are reported by category and project maturity sub-class, unrisked and risked for chance of development. The estimates are in accordance with the definitions and guidelines in the COGE Handbook and NI 51-101. Please note that reserves and Contingent Resources involve different risks associated with achieving commerciality. Under the fiscal conditions, including commodity price and cost assumptions, applied in the estimation of reserves, the likelihood that a project will achieve commerciality is effectively 100%, whereas the likelihood of a Contingent Resource achieving commerciality will be less than 100%.

Summary of Gross Bitumen Reserves as of December 31, 2018
(Forecast Prices and Costs)

	Bitumen - Reserves Category		
	Total Proved	**Total Proved Plus Probable**	**Total Proved Plus Probable Plus Possible**
Gross Reserves (Mbbl)	159,153	311,395	401,210

Summary of Gross Bitumen Contingent Resources as of December 31, 2018
(Forecast Prices and Costs)

	Bitumen - Contingent Resource Category		
Project Maturity Sub-Class(1)	**Low Estimate**	**Best Estimate**	**High Estimate**
Development Pending(2) - Unrisked (Mbbl)	16,256	35,773	59,511
Chance of Development	95%	95%	95%
Development Pending - Risked (Mbbl)	15,443	33,985	56,535
Development Unclarified(3) - Unrisked (Mbbl)	-	66,677	97,763
Chance of Development	-	58%	58%
Development Unclarified - Risked (Mbbl)	-	38,406	55,160

Notes:

(1) Project maturity describes the stage of an exploration or development project and broadly corresponds to the chance of commerciality of the project. The project maturity sub-classes (in order of increasing chance of commerciality) are: development not viable, development unclarified, development on hold and development pending. The boundaries between the maturity sub-classes represent "decision gates" that reflect the actions (business decisions) required by the resource owner to move the project up the maturity "ladder" toward commercial production. The project maturity sub-class is accompanied by an estimate of the probability of progressing to the next level of maturity, which is independent of the uncertainty associated with the range of recoverable volumes.

(2) Development Pending describes the status of a project where resolution of the final conditions for development is being actively pursued (high chance of development).

(3) Development Unclarified describes the status of a project where the evaluation is incomplete and there is ongoing activity to resolve any risks and uncertainties.

Summary of Net Bitumen Reserves as of December 31, 2018
(Forecast Prices and Costs)

	Bitumen - Reserves Category		
	Total Proved	Total Proved Plus Probable	Total Proved Plus Probable Plus Possible
Net Reserves (Mbbl)	120,970	230,741	288,676

Summary of Net Bitumen Contingent Resources as of December 31, 2018
(Forecast Prices and Costs)

	Bitumen - Contingent Resource Category		
Project Maturity Sub-Class(1)	Low Estimate	Best Estimate	High Estimate
Development Pending(2) - Unrisked (Mbbl)	12,910	27,262	45,827
Chance of Development	95%	95%	95%
Development Pending - Risked (Mbbl)	12,265	25,899	43,535
Development Unclarified(3) - Unrisked (Mbbl)	-	52,606	73,060
Chance of Development		58%	58%
Development Unclarified - Risked (Mbbl)	-	30,301	42,082

Notes:

(1) Project maturity describes the stage of an exploration or development project and broadly corresponds to the chance of commerciality of the project. The project maturity sub-classes (in order of increasing chance of commerciality) are: development not viable, development unclarified, development on hold and development pending. The boundaries between the maturity sub-classes represent "decision gates" that reflect the actions (business decisions) required by the resource owner to move the project up the maturity "ladder" toward commercial production. The project maturity sub-class is accompanied by an estimate of the probability of progressing to the next level of maturity, which is independent of the uncertainty associated with the range of recoverable volumes.

(2) Development Pending describes the status of a project where resolution of the final conditions for development is being actively pursued (high chance of development).

(3) Development Unclarified describes the status of a project where the evaluation is incomplete and there is ongoing activity to resolve any risks and uncertainties.

Summary of Bitumen Reserves
Net Present Value of Future Net Revenue as of December 31, 2018
(Forecast Prices and Costs)

	Before Income Taxes Discounted at (%/year) - $MM				
Reserves Category	0%	5%	10%	15%	20%
Total Proved	4,043	2,250	1,436	1,018	779
Total Proved Plus Probable	8,161	4,149	2,420	1,577	1,117
Total Proved Plus Probable Plus Possible	12,097	5,371	2,946	1,886	1,341

Summary of Bitumen Contingent Resources
Net Present Value of Future Net Revenue as of December 31, 2018
(Forecast Prices and Costs)

			Before Income Taxes Discounted at (%/year) - $MM				
Project Maturity Sub-Class			**0%**	**5%**	**10%**	**15%**	**20%**
Development Pending	Low Estimate	Unrisked	335	86	23	6	2
		Chance of Development	95%	95%	95%	95%	95%
		Risked	318	81	22	6	2
	Best Estimate	Unrisked	891	226	59	16	4
		Chance of Development	95%	95%	95%	95%	95%
		Risked	847	214	57	15	4
	High Estimate	Unrisked	1,063	644	337	171	86
		Chance of Development	95%	95%	95%	95%	95%
		Risked	1,010	612	320	162	82
Development Unclarified	Low Estimate	Unrisked	-	-	-	-	-
		Chance of Development	58%	58%	58%	58%	58%
		Risked	-	-	-	-	-
	Best Estimate	Unrisked	1,089	382	115	11	(27)
		Chance of Development	58%	58%	58%	58%	58%
		Risked	627	220	66	7	(16)
	High Estimate	Unrisked	2,116	668	212	53	(7)
		Chance of Development	58%	58%	58%	58%	58%
		Risked	1,219	385	122	30	(4)

Note:

(1) 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 risked net present value of future net revenue will be realized.

Proved Reserves, Probable Reserves and Possible Reserves have been assigned within the region of the current and proposed commercial development areas where the pool has been sufficiently delineated. The Proved and Probable Reserves attributed to the Lindbergh property have been included in the reserves disclosed under "Statement of Oil and Gas Reserves and Reserves Data".

Contingent Resources have been assigned to the remaining areas of the reservoir within the property that meet certain minimum criteria. Contingent Resources are estimated on the basis of a technically feasible SAGD recovery project having been defined. However, there is uncertainty that it will be commercially viable to produce any portion of the Contingent Resources.

A significant portion of the resource volumes are still classified as a Contingent Resource rather than a reserve due to the following contingencies:

- Higher evaluation well density – additional drilling within the area of the known accumulation is required to allow further project and reserves definition.
- Firm development plans and company commitment for future development phases – confirmation of corporate intent to proceed with defined expansion plans, beyond the initial expansion phase, within an acceptable time period.
- Final project design and sanctioning for any potential future expansion phases.

The Contingent Resources are evaluated based on the same fiscal conditions used in the assessment of reserves and, as such, are expected to be economic. They are estimated on the basis of established technology, namely the application of SAGD technology in sandstone reservoirs. We anticipate the contingencies mentioned above will be satisfied over time which should allow us to book some portion of the Contingent Resources as Proved Reserves, Probable Reserves and Possible Reserves in future years.

The development pending project maturity sub-class relates to the Contingent Resources assigned to areas of the reservoir around the edge of the main Lindbergh pool. It is an extension of the existing commercial development and within the area covered by the Phase 2 expansion application which received regulatory approval in 2016. There is a very high expectation that development will occur for the remaining development pending Contingent Resources but requires a firm development plan and commitment by the Corporation to proceed with the required capital expenditure for additional wells, making use of existing and proposed expansion facility capacity. A chance of development of 95% has thus been assigned to these development pending Contingent Resources.

The development unclarified project maturity sub-class relates to the Contingent Resources assigned to a standalone SAGD development on the Muriel Lake lands. The development unclarified Contingent Resources here are based on a pre-development study. The total Best Estimate gross unrisked capital cost to achieve commercial production is estimated to be $435 million with first major capital expenditures forecast in 2024 and production to commence in 2026. There is more risk associated with the chance of developing this portion of the project relating to the uncertainty in the economics, which requires high quality cost estimates, regulatory approval of a standalone development and the need for a firm development plan which will proceed in a reasonable timeframe. Based on these uncertainties, a chance of development of 58% has been assigned.

Selina Oil Sands Contingent Resources

The Selina property is a potential joint venture SAGD development that is described above under *"Principal Producing Properties - Lindbergh"*.

GLJ has evaluated the Selina property as of December 31, 2018, and has assigned Contingent Resources based on the potential for developing the oil sands reservoir as a SAGD project. The evaluation was limited to portions of the reservoir amenable to SAGD. The profitability of the proposed project will be sensitive to oil prices and reservoir quality.

The tables below summarize the estimated volumes and net present value of Future Net Revenue for Pengrowth's Company Interest Contingent Resources attributable to the Selina property based upon forecast prices and costs. Contingent Resources are reported by category and project maturity sub-class, unrisked and risked for chance of development. The estimates are in accordance with the definitions and guidelines in the COGE Handbook and NI 51-101. Please note that Contingent Resources involve risks associated with achieving commerciality. Under the fiscal conditions, including commodity price and cost assumptions, applied in the estimation of Contingent Resources, the likelihood that a project will achieve commerciality is less than 100%.

Summary of Gross Bitumen Contingent Resources as of December 31, 2018
(Forecast Prices and Costs)

	Bitumen - Contingent Resource Category		
Project Maturity Sub-Class[1]	**Low Estimate**	**Best Estimate**	**High Estimate**
Development Pending[2] - Unrisked (Mbbl)	37,090	56,088	74,632
Chance of Development	90%	90%	90%
Development Pending - Risked (Mbbl)	33,381	50,479	67,169

Notes:

(1) Project maturity describes the stage of an exploration or development project and broadly corresponds to the chance of commerciality of the project. The project maturity sub-classes (in order of increasing chance of commerciality) are: development not viable, development unclarified, development on hold and development pending. The boundaries between the maturity sub-classes represent "decision gates" that reflect the actions (business decisions) required by the resource owner to move the project up the maturity "ladder" toward commercial production. The project maturity sub-class is accompanied by an estimate of the probability of progressing to the next level of maturity, which is independent of the uncertainty associated with the range of recoverable volumes.

(2) Development Pending describes the status of a project where resolution of the final conditions for development is being actively pursued (high chance of development).

Summary of Net Bitumen Contingent Resources as of December 31, 2018
(Forecast Prices and Costs)

	Bitumen - Contingent Resource Category		
Project Maturity Sub-Class[1]	**Low Estimate**	**Best Estimate**	**High Estimate**
Development Pending[2] - Unrisked (Mbbl)	30,814	44,467	57,548
Chance of Development	90%	90%	90%
Development Pending - Risked (Mbbl)	27,733	40,021	51,793

Notes:

(1) Project maturity describes the stage of an exploration or development project and broadly corresponds to the chance of commerciality of the project. The project maturity sub-classes (in order of increasing chance of commerciality) are: development not viable, development unclarified, development on hold and development pending. The boundaries between the maturity sub-classes represent "decision gates" that reflect the actions (business decisions) required by the resource owner to move the project up the maturity "ladder" toward commercial production. The project maturity sub-class is accompanied by an estimate of the probability of progressing to the next level of maturity, which is independent of the uncertainty associated with the range of recoverable volumes.

(2) Development Pending describes the status of a project where resolution of the final conditions for development is being actively pursued (high chance of development).

Summary of Bitumen Contingent Resources
Net Present Value of Future Net Revenue as of December 31, 2018
(Forecast Prices and Costs)

			Before Income Taxes Discounted at (%/year) - $MM				
Project Maturity Sub-Class			**0%**	**5%**	**10%**	**15%**	**20%**
Development Pending	Low Estimate	Unrisked	633	230	67	(5)	(38)
		Chance of Development	90%	90%	90%	90%	90%
		Risked	570	207	60	(4)	(34)
	Best Estimate	Unrisked	1,400	468	165	46	(6)
		Chance of Development	90%	90%	90%	90%	90%
		Risked	1,260	421	148	42	(6)
	High Estimate	Unrisked	2,335	650	217	68	6
		Chance of Development	90%	90%	90%	90%	90%
		Risked	2,101	585	195	61	5

Note:

(1) 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 risked net present value of future net revenue will be realized.

Pengrowth has a 50% working interest in the Selina oil sands property. It is located approximately 30km northeast of our Lindbergh property where we currently operate a commercial SAGD project. The Selina property contains a similar bitumen accumulation in the Lloydminster formation to Lindbergh.

Contingent Resources have been assigned to areas of the reservoir within the Selina property that meet certain minimum criteria. Contingent Resources are estimated on the basis of a technically feasible SAGD recovery project having been defined by analogy to our nearby Lindbergh property. However, there is uncertainty that it will be commercially viable to produce any portion of the Contingent Resources.

The resource volumes are classified as a Contingent Resource rather than a reserve due to the following contingencies:

- Higher evaluation well density - additional drilling within the area of the known accumulation is required to allow further project and reserves definition.
- Regulatory approval of the EPEA application for commercial development is required.
- Firm development plans, including high quality capital estimates, and each owner's commitment for future development - confirmation of corporate intent to proceed with defined development plans within an acceptable time period.
- Final project design and sanctioning for commercial development.

The Contingent Resources are evaluated based on the same fiscal conditions used in the assessment of reserves and, as such, are expected to be economic. They are estimated on the basis of established technology, namely the application of SAGD technology in sandstone reservoirs. We anticipate the contingencies mentioned above will be satisfied over time which should allow us to book some portion of the Contingent Resources as Proved Reserves, Probable Reserves and Possible Reserves in future years.

The Contingent Resources at Selina have a development pending project maturity sub-classification. In December 2016, Pengrowth and Koch jointly submitted an EPEA application for a commercial SAGD development. The development pending Contingent Resources are based on a pre-development study. The total Best Estimate gross capital cost to achieve commercial production is estimated to be $503 million with first major capital expenditures forecast in 2021 and production to commence in 2023. There is a high expectation that development will occur but requires regulatory approval, a firm development plan and commitment by the owners to proceed with the required capital expenditure for the well pairs and proposed central facility. A chance of development of 90% has thus been assigned to the development pending Contingent Resources.

Groundbirch Reserves and Contingent Resources

The Groundbirch property is described above under *"Principal Producing Properties - Groundbirch"*.

Commercial production at Groundbirch was established in 2010 and there are 22 wells currently producing. For those areas producing and immediately adjacent to existing wells, GLJ has assigned Proved Reserves, Probable Reserves and Possible Reserves. For areas outside of this and in prospective deeper intervals, GLJ has completed a Contingent Resource assessment. The expectation is to continue developing our lands with four to five wells per section in each of multiple layers to fully exploit the thick reservoir and keep our existing gas processing facility full. With favourable economic conditions, our plan is to expand our facility capacity and increase the pace of development in the near future. In evaluating reserves and Contingent Resources, as of December 31, 2018, the GLJ forecasts are consistent with this development scenario.

The tables below summarize the estimated volumes and net present value of Future Net Revenue for Pengrowth's Company Interest reserves and Contingent Resources attributable to the Groundbirch property based upon forecast prices and costs. Contingent Resources are reported by category and project maturity sub-class, unrisked and risked for chance of development. The estimates are in accordance with the definitions and guidelines in the COGE Handbook and NI 51-101. Please note that reserves and Contingent Resources involve different risks associated with achieving commerciality. Under the fiscal conditions, including commodity price and cost assumptions, applied in the estimation of reserves, the likelihood that a project will achieve commerciality is effectively 100%, whereas the likelihood of a Contingent Resource achieving commerciality will be less than 100%.

Summary of Gross Shale Gas Reserves as of December 31, 2018
(Forecast Prices and Costs)

	Shale Gas - Reserves Category		
	Total Proved	Total Proved Plus Probable	Total Proved Plus Probable Plus Possible
Gross Reserves (MMcf)	192,998	792,700	947,055

Summary of Gross Shale Gas Contingent Resources as of December 31, 2018
(Forecast Prices and Costs)

	Shale Gas - Contingent Resource Category		
Project Maturity Sub-Class(1)	Low Estimate	Best Estimate	High Estimate
Development Pending(2) - Unrisked (MMcf)	503,718	730,466	914,067
Chance of Development	85%	85%	85%
Development Pending - Risked (MMcf)	428,160	620,896	776,957

Notes:

(1) Project maturity describes the stage of an exploration or development project and broadly corresponds to the chance of commerciality of the project. The project maturity sub-classes (in order of increasing chance of commerciality) are: development not viable, development unclarified, development on hold and development pending. The boundaries between the maturity sub-classes represent "decision gates" that reflect the actions (business decisions) required by the resource owner to move the project up the maturity "ladder" toward commercial production. The project maturity sub-class is accompanied by an estimate of the probability of progressing to the next level of maturity, which is independent of the uncertainty associated with the range of recoverable volumes.

(2) Development Pending describes the status of a project where resolution of the final conditions for development is being actively pursued (high chance of development).

Summary of Net Shale Gas Reserves as of December 31, 2018
(Forecast Prices and Costs)

	Shale Gas - Reserves Category		
	Total Proved	Total Proved Plus Probable	Total Proved Plus Probable Plus Possible
Net Reserves (MMcf)	170,413	669,867	790,862

Summary of Net Shale Gas Contingent Resources as of December 31, 2018
(Forecast Prices and Costs)

	Shale Gas - Contingent Resource Category		
Project Maturity Sub-Class[(1)]	**Low Estimate**	**Best Estimate**	**High Estimate**
Development Pending[(2)] - Unrisked (MMcf)	417,864	597,519	739,269
Chance of Development	85%	85%	85%
Development Pending - Risked (MMcf)	355,184	507,891	628,379

Notes:

(1) Project maturity describes the stage of an exploration or development project and broadly corresponds to the chance of commerciality of the project. The project maturity sub-classes (in order of increasing chance of commerciality) are: development not viable, development unclarified, development on hold and development pending. The boundaries between the maturity sub-classes represent "decision gates" that reflect the actions (business decisions) required by the resource owner to move the project up the maturity "ladder" toward commercial production. The project maturity sub-class is accompanied by an estimate of the probability of progressing to the next level of maturity, which is independent of the uncertainty associated with the range of recoverable volumes.

(2) Development Pending describes the status of a project where resolution of the final conditions for development is being actively pursued (high chance of development).

Summary of Shale Gas Reserves
Net Present Value of Future Net Revenue as of December 31, 2018
(Forecast Prices and Costs)

	Before Income Taxes Discounted at (%/year) - $MM				
Reserves Category	**0%**	**5%**	**10%**	**15%**	**20%**
Total Proved	294	165	100	64	42
Total Proved Plus Probable	1,540	646	322	178	104
Total Proved Plus Probable Plus Possible	2,096	790	378	206	121

Summary of Shale Gas Contingent Resources
Net Present Value of Future Net Revenue as of December 31, 2018
(Forecast Prices and Costs)

			Before Income Taxes Discounted at (%/year) - $MM				
Project Maturity Sub-Class			**0%**	**5%**	**10%**	**15%**	**20%**
Development Pending	Low Estimate	Unrisked	984	271	82	26	8
		Chance of Development	85%	85%	85%	85%	85%
		Risked	836	230	70	22	7
	Best Estimate	Unrisked	1,765	475	151	52	19
		Chance of Development	85%	85%	85%	85%	85%
		Risked	1,500	404	128	44	16
	High Estimate	Unrisked	2,433	636	201	72	27
		Chance of Development	85%	85%	85%	85%	85%
		Risked	2,068	541	171	61	23

Note:

(1) 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 risked net present value of future net revenue will be realized.

Proved Reserves, Probable Reserves and Possible Reserves have been assigned to existing wells and the adjacent undeveloped lands where the Montney reservoir has been sufficiently delineated and development is expected to occur in a reasonable timeframe. The Proved and Probable Reserves attributed to the Groundbirch property have been included in the reserves disclosed under "Statement of Oil and Gas Reserves and Reserves Data".

Contingent Resources are assigned on the basis of a technically feasible recovery project having been defined using established technology, which includes the drilling of horizontal wells and the application of multi-stage fracture techniques. These Contingent Resources are expected to be economic to develop. The Groundbirch Montney shale gas resource is in the early stage of development. Contingent Resources are assigned by GLJ beyond those areas with reserves, to regions of the field where the zone is delineated to an appropriate level to understand the reservoir, and to remove reservoir risk. Additional drilling, completion and test data is required for planning and design purposes with respect to well spacing, pipeline and facility capacity and scheduling of further development. The reclassification of these Contingent Resources as reserves is contingent upon:

- A positive commercial environment with respect to prices and capital costs;
- The need for long term competitive drilling and completion costs;
- Creation and execution of a development plan that will proceed in an acceptable time period which involves an aggressive drilling pace and significant facility expansion; and
- Corporate approval and commitment to spend the required capital to develop these Contingent Resources.

Pengrowth is currently actively pursuing resolution of these contingencies, however, there is uncertainty that it will be commercially viable to produce any portion of the Contingent Resources.

The Contingent Resources are sub-classified on the basis of their project maturity level as development pending. As we step out further from the existing development, there is risk associated with the chance of development as it is forecast further into the future, requiring long term development plans and an ongoing capital commitment by the Corporation.

There is a high expectation that the development pending Contingent Resources will be produced and a chance of development of 85 percent has been assigned. The Contingent Resources are an extension of the existing area where there is production and undeveloped reserves assigned. The uncertainties relate to longer term drilling and completion costs and a development plan and commitment by Pengrowth to pursue development within the next five year period. Growth plans are in place for this to happen.

APPENDIX B

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

To the board of directors of Pengrowth Energy Corporation (the "**Corporation**"):

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

2. The reserves data and contingent resources data are the responsibility of the Corporation's management. Our responsibility is to express an opinion on the reserves data and contingent 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 reserves data and contingent resources data are free of material misstatement. An evaluation also includes assessing whether the reserves data and contingent resources 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 Corporation evaluated for the year ended December 31, 2018, and identifies the respective portions thereof that we have evaluated and reported on to the Corporation's management/board of directors:

Independent Qualified Reserves Evaluator or Auditor	Effective Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate - $M)			
			Audited	Evaluated	Reviewed	**Total**
GLJ Petroleum Consultants	December 31, 2018	Canada	-	2,760,012	-	**2,760,012**

6. The following tables set forth the risked volume and risked net present value of future net revenue of contingent resources (before deduction of income taxes) attributed to contingent resources, estimated using forecast prices and costs and calculated using a discount rate of 10%, included in the Corporation's statement prepared in accordance with Form 51-101F1 and identifies the respective portions of the contingent resources data that we have evaluated and reported on to the Corporation's management/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	Risked Volume (MMboe)	Risked Net Present Value of Future Net Revenue (before income taxes, 10% discount rate - $M)		
					Audited	Evaluated	**Total**
Development Pending Contingent Resources (2C)	GLJ Petroleum Consultants	December 31, 2018	Canada	187.9	-	332,725	**332,725**

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 (MMboe)
Development Unclarified Contingent Resources	GLJ Petroleum Consultants	December 31, 2018	Canada	38.4

7. In our opinion, the reserves data and contingent 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 reserves data and contingent resources data that we reviewed but did not audit or evaluate.

8. We have no responsibility to update our reports referred to in paragraphs 5 and 6 for events and circumstances occurring after the effective date of our reports.

9. Because the reserves data and contingent resources data are based on judgements regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, February 25, 2019

(signed) "*Todd J. Ikeda*"

Todd J. Ikeda, P.Eng.
Vice President

APPENDIX C

FORM 51-101F3
REPORT OF
MANAGEMENT AND DIRECTORS ON
RESERVES DATA AND OTHER INFORMATION

Management of Pengrowth Energy Corporation (the "**Corporation**") are responsible for the preparation and disclosure of information with respect to the Corporation's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2018, estimated using forecast prices and costs and includes contingent resources data, which are risked estimates of the volume of contingent resources and related risked net present value of future net revenue as at December 31, 2018, estimated using forecast prices and costs.

An independent qualified reserves evaluator has evaluated the Corporation's reserves data and contingent resources data. The report of the independent qualified reserves evaluator will be filed with securities regulatory authorities concurrently with this report.

The Reserves, Health, Safety and Environment Committee of the board of directors of the Corporation has:

(a) reviewed the Corporation's procedures for providing information to the independent qualified reserves evaluator;

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

(c) reviewed the reserves data and the contingent resources data with management and the independent qualified reserves evaluator.

The Reserves, Health, Safety and Environment Committee of the board of directors has reviewed the Corporation'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, Health, Safety and Environment Committee, approved:

(a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data and contingent resources data and other oil and gas information;

(b) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluator on the reserves data, contingent resources data, or prospective resources data; and

(c) the content and filing of this report.

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

(signed) "*Peter Sametz*"
Peter Sametz
President and Chief Executive Officer

(signed) "*Randall S. Steele*"
Randall S. Steele
Chief Operating Officer

(signed) "*James D. McFarland*"
James D. McFarland
Director

(signed) "*Kelvin B. Johnston*"
Kelvin B. Johnston
Chairman of the Board

February 27, 2019

APPENDIX D

AUDIT AND RISK COMMITTEE
TERMS OF REFERENCE

	PENGROWTH ENERGY CORPORATION **Policies and Practices**	**Page** **1 of 11**
TERMS OF REFERENCE **AUDIT AND RISK COMMITTEE**		

OBJECTIVES

The Audit and Risk Committee (the "**Committee**") is appointed by the board of directors (the "**Board**") of Pengrowth Energy Corporation (the "**Corporation**") to assist the Board in fulfilling its oversight responsibilities. The Corporation, together with its subsidiaries and affiliates, are collectively referred to herein as "**Pengrowth**".

The Committee's primary duties and responsibilities are to:

- monitor the performance of Pengrowth's internal audit function and the integrity of Pengrowth's financial reporting process and systems of internal controls regarding finance, accounting, and legal compliance;
- assist Board oversight of: (i) the integrity of Pengrowth's financial statements; (ii) Pengrowth's compliance with legal and regulatory requirements; and (iii) the performance of Pengrowth's internal audit function and independent auditors;
- monitor the independence, qualification and performance of Pengrowth's external auditors;
- provide an avenue of communication among the external auditors, the internal auditors, management and the Board; and
- oversee Pengrowth's risk management processes.

The Committee will continuously review and modify its terms of reference with regard to, and to reflect changes in, the business environment, industry standards on matters of corporate governance, additional standards which the Committee believes may be applicable to Pengrowth's business, the location of Pengrowth's business and its shareholders and the application of laws and policies.

COMPOSITION

Committee members must meet the requirements of applicable securities laws and each of the stock exchanges on which the shares of Pengrowth trade. The Committee shall consist of not less than three and not more than six directors all of whom shall be "independent" and "financially literate", as those terms are defined in National Instrument 52-110 *Audit Committees* ("**NI 52-110**") of the Canadian Securities Administrators (as set out in Schedule "A" hereto), Rule 10A-3 promulgated under the *Securities Exchange Act of 1934* (as set out in Schedule "B" hereto), and Section 303A.02 of the New York Stock Exchange Listed Company Manual (as set out in Schedule "C" hereto), as applicable, and as "financially literate" is interpreted by the Board in its business judgement. In addition, at least one member of the Committee must have accounting or related financial management expertise as defined by paragraph (8) of general instruction B to Form 40-F and as interpreted by the Board in its business judgement.

The members of the Committee shall be appointed by the Board as members of the Committee and shall continue as such until their successors are appointed or until they cease to be directors of the Corporation. At any time, the Board may fill any vacancy in the membership of the Committee.

The chair of the Committee (the "**Chair**") will be appointed by the Board or, if one is not appointed, the members of the Committee may elect a chair by vote of a majority of the membership of such committee.

MEETINGS AND MINUTES

The Committee shall meet at least four times annually, or more frequently if determined necessary to carry out its responsibilities.

A meeting may be called by any member of the Committee, the Chairman of the Board or the President and Chief Executive Officer ("**CEO**") of the Corporation. A notice of the time and place of every meeting of the Committee shall be given in writing to each member of the Committee at least two business days prior to the time fixed for such meeting, unless notice of a meeting is waived by all members entitled to attend. Attendance of a member of the Committee at a meeting shall constitute waiver of notice of the meeting except where a member attends a meeting for the express purpose of objecting to the transaction of any business on the grounds that the meeting was not lawfully called.

A quorum for meetings of the Committee shall require a majority of its members present in person or by telephone. If the Chair of the Committee is not present at any meeting of the Committee, one of the other members of the Committee present at the meeting will be chosen to preside by a majority of the members of the Committee present at that meeting.

The President and CEO of the Corporation shall be available to advise the Committee, shall receive notice of meetings and may attend meetings of the Committee at the invitation of the Chair. Other management representatives, as well as Pengrowth's internal and external auditors, shall be invited to attend as necessary. Notwithstanding the foregoing, the Chair of the Committee shall hold *in camera* sessions, without management present, at every meeting of the Committee.

Decisions of the Committee shall be determined by a majority of the votes cast.

The Committee shall appoint a member of the Committee, the Corporate Secretary or another officer of Pengrowth to act as secretary at each meeting for the purpose of recording the minutes of each meeting.

The Committee shall provide the Board with a summary of all meetings together with a copy of the minutes from such meetings. Where minutes have not yet been prepared, the Chair shall provide the Board with oral reports on the activities of the Committee. All information reviewed and discussed by the Committee at any meeting shall be referred to in the minutes and made available for examination by the Board upon request to the Chair.

SCOPE, DUTIES AND RESPONSIBILITIES

MANDATORY DUTIES

<u>REVIEW PROCEDURES</u>

Pursuant to the requirements of NI 52-110 and other applicable laws, the Committee will:

1. Review and reassess the adequacy of the Committee's terms of reference at least annually, submit the terms of reference to the Board for approval and have the document published annually in Pengrowth's annual information circular and at least every three years in accordance with the regulations of the United States' Securities and Exchange Commission.

2. Prior to filing or public distribution, review, discuss with management and the internal and external auditors and recommend to the Board for approval, Pengrowth's audited annual financial statements, annual earnings press releases, AIF, all financial statements including the related management's discussion and analysis required in prospectuses and other offering memoranda, financial statements required by regulatory authorities, all prospectuses and all documents which may be incorporated by reference into a prospectus, including without limitation, the annual information circular. Approve, on behalf of the Board, Pengrowth's interim financial statements and related management's discussion and analysis and interim earnings press releases. This review should include discussions with management, the internal auditors and the external auditors of significant issues regarding accounting principles, practices and judgements. Discuss any significant changes to Pengrowth's accounting principles and any matters required to be communicated to the Committee by the external auditors in accordance with generally accepted auditing standards.

3. Ensure that adequate procedures are in place for the review of Pengrowth's public disclosure of financial information extracted or derived from Pengrowth's financial statements, other than the public disclosure referred to in paragraph 2 above and periodically assess the adequacy of those procedures.

4. Be responsible for reviewing the disclosure contained in Pengrowth's AIF as required by Form 52-110F1 Audit Committee Information Required in an AIF, attached to NI 52-110. If proxies are solicited for the election of directors of Pengrowth, the Committee shall be responsible for ensuring that Pengrowth's information circular includes a cross-reference to the sections in Pengrowth's AIF that contain the information required by Form 52-110F1.

EXTERNAL AUDITORS

1. The Committee shall advise the external auditors of their accountability to the Committee and the Board as representatives of Pengrowth's shareholders to whom the external auditors are ultimately responsible. The external auditors shall report directly to the Committee. The Committee is directly responsible for overseeing the work of the external auditors, shall review at least annually the independence and performance of the external auditors and shall annually recommend to the Board the appointment of the external auditors or approve any discharge of auditors when circumstances warrant. The Committee shall, on an annual basis, obtain and review a report by the external auditor describing: (i) the external auditor's internal quality-control procedures; (ii) any material issues raised by the most recent internal quality-control review, or peer review, of the external auditors, or by any inquiry or investigation by governmental or professional authorities, within the preceding five years, respecting one or more independent audits carried out by the external auditors, and any steps taken to deal with any such issues; and (iii) all relationships between the independent auditor and Pengrowth.

2. Approve the fees and other compensation to be paid to the external auditors.

3. Pre-approve all services to be provided to Pengrowth or its subsidiary entities by Pengrowth's external auditors and all related terms of engagement.

OTHER COMMITTEE RESPONSIBILITIES

1. Establish procedures for: (i) the receipt, retention and treatment of complaints received by Pengrowth regarding accounting, internal accounting controls, or auditing matters; and (ii) the confidential and anonymous submission by employees of Pengrowth of concerns regarding questionable accounting or auditing matters.

2. Review and approve Pengrowth's hiring policies regarding partners, employees and former partners and employees of the present and former external auditors of Pengrowth.

DISCRETIONARY DUTIES

The Committee's responsibilities may, at the Board's discretion, also include the following:

REVIEW PROCEDURES

1. In consultation with management, the internal auditors and the external auditors, consider the integrity of Pengrowth's financial reporting processes and controls and the performance of Pengrowth's internal financial accounting staff; discuss significant financial risk exposures and the steps management has taken to monitor, control and report such exposures; and review significant findings prepared by the internal or external auditors together with management's responses.

2. Review, with financial management, the internal auditors and the external auditors, Pengrowth's policies relating to risk management and risk assessment.

3. Meet separately with each of management, the internal auditors and the external auditors to discuss difficulties or concerns, specifically: (i) any difficulties encountered in the course of the audit work, including any restrictions on the scope of activities or access to requested information, and any significant disagreements with management; (ii) any changes required in the planned scope of the audit; and (iii) the responsibilities, budget, and staffing of the internal audit function, and report to the Board on such meetings.

4. Conduct an annual performance evaluation of the Committee.

INTERNAL AUDITORS

1. Review the annual audit plans of the internal auditors.

2. Review the significant findings prepared by the internal auditors and recommendations issued by any external party relating to internal audit issues, together with management's response.

3. Review the adequacy of the resources of the internal auditors to ensure the objectivity and independence of the internal audit function.

4. Consult with management on management's appointment, replacement, reassignment or dismissal of the internal auditors.

5. Ensure that the internal auditors have access to the Chairman of the Board and the President and CEO.

EXTERNAL AUDITORS

1. On an annual basis, the Committee should review and discuss with the external auditors all significant relationships they have with Pengrowth that could impair the auditors' independence.

2. The Committee shall review the external auditors audit plan – discuss scope, staffing, locations, and reliance upon management and general audit approach.

3. Consider the external auditors' judgments about the quality and appropriateness of Pengrowth's accounting principles as applied in its financial reporting.

4. Be responsible for the resolution of disagreements between management and the external auditors regarding financial performance.

5. Ensure compliance by the external auditors with the requirements set forth in National Instrument 52 108 Auditor Oversight.

6. Ensure that the external auditors are participants in good standing with the Canadian Public Accountability Board ("CPAB") and participate in the oversight programs established by the CPAB from time to time and that the external auditors have complied with any restrictions or sanctions imposed by the CPAB as of the date of the applicable auditor's report relating to Pengrowth's annual audited financial statements.

7. Monitor compliance with the lead auditor rotation requirements of Regulation S-X.

RISK MANAGEMENT POLICIES

Review and recommend for approval by the Board changes considered advisable, after consultation with officers of the Corporation, to the Corporation's policies relating to:

(a) The risks inherent in the Corporation's businesses, facilities, strategic direction;

(b) The overall risk management strategies (including insurance coverage);

(c) The risk retention philosophy and the resulting uninsured exposure of the Corporation; and

(d) The loss prevention policies, risk management and hedging programs, and standard and accountabilities of the Corporation in the context of competitive and operational considerations.

RISK MANAGEMENT PROCESSES

Review with management at least annually the Corporation's processes to identify, monitor, evaluate and address important enterprise-wide business risks.

FINANCIAL RISK MANAGEMENT

Review with management activity related to management of financial risks to the Corporation.

OTHER COMMITTEE RESPONSIBILITIES

1. On at least an annual basis, review with Pengrowth's legal counsel any legal matters that could have a significant impact on the organization's financial statements, Pengrowth's compliance with applicable laws and regulations, and inquiries received from regulators or governmental agencies.

2. Annually prepare a report to shareholders as required by the United States' Securities and Exchange Commission; the report should be included in Pengrowth's annual information circular.

3. Ensure due compliance with each obligation to certify, on an annual and interim basis, internal control over financial reporting and disclosure controls and procedures in accordance with applicable securities laws and regulations.

4. Review all exceptions to established policies, procedures and internal controls of Pengrowth, which have been approved by any two officers of Pengrowth.

5. Perform any other activities consistent with this Charter, Pengrowth's by-laws, and other governing law as the Committee or the Board deems necessary or appropriate.

6. Maintain minutes of meetings and periodically report to the Board on significant results of the foregoing activities.

COMMUNICATION, AUTHORITY TO ENGAGE ADVISORS AND EXPENSES

The Committee shall have direct access to such officers and employees of the Corporation, including the Corporation's internal and external auditors and to any other consultants or advisors, as well as to such information respecting Pengrowth it considers necessary to perform its duties and responsibilities.

Any employee may bring before the Committee, on a confidential basis, any concerns relating to matters over which the Committee has oversight responsibilities.

The Committee has the authority to engage the external auditors, independent legal counsel and other advisors as it determines necessary to carry out its duties and to set the compensation for any auditors, counsel and other advisors, 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 appropriate by the Committee in order to carry out its duties.

As last amended by the Board of Pengrowth on November 3, 2016.

Last reviewed and approved by the Board of Pengrowth on November 9, 2017.

Schedule "A"

National Instrument 52-110 - Audit Committees

Meaning of "Independence"

1. An audit committee member is independent if he or she has no direct or indirect material relationship with Pengrowth.

2. For the purposes of paragraph 1, a "material relationship" is a relationship which could, in the view of the Board, be reasonably expected to interfere with the exercise of a member's independent judgment.

3. Despite paragraph 2, the following individuals are considered to have a material relationship with Pengrowth:

   (a) an individual who is, or has been within the last three years, an employee or executive officer of Pengrowth;

   (b) an individual whose immediate family member is, or has been within the last three years, an executive officer of Pengrowth;

   (c) an individual who:

      i. is a partner of a firm that is Pengrowth's internal or external auditor,

      ii. is an employee of that firm, or

      iii. was within the last three years a partner or employee of that firm and personally worked on Pengrowth's audit within that time;

   (d) an individual whose spouse, minor child or stepchild, or child or stepchild who shares a home with the individual:

      i. is a partner of a firm that is Pengrowth's internal or external auditor,

      ii. is an employee of that firm and participates in its audit, assurance or tax compliance (but not tax planning) practice, or

      iii. was within the last three years a partner or employee of that firm and personally worked on Pengrowth's audit within that time;

   (e) an individual who, or whose immediate family member, is or has been within the last three years, an executive officer of an entity if any of Pengrowth's current executive officers serves or served at that same time on the entity's compensation committee; and

   (f) an individual who received, or whose immediate family member who is employed as an executive officer of Pengrowth received, more than $75,000 in direct compensation from Pengrowth during any 12 month period within the last three years.

4. For the purposes of paragraphs 3(c) and 3(d), a partner does not include a fixed income partner whose interest in the firm that is the internal or external auditor is limited to the receipt of fixed amounts of compensation (including deferred compensation) for prior service with that firm if the compensation is not contingent in any way on continued service.

5. For the purposes of paragraph 3(f), direct compensation does not include

   (a) remuneration for acting as a member of the Board or of any committee of the Board, and

   (b) the receipt of fixed amounts of compensation under a retirement plan (including deferred compensation) for prior service with Pengrowth if the compensation is not contingent in any way on continued service.

6. Despite paragraph 3, an individual will not be considered to have a material relationship with Pengrowth solely because the individual or his or her immediate family member

(a) has previously acted as an interim chief executive officer of Pengrowth, or

(b) acts, or has previously acted, as a chair or vice-chair of the Board or of any committee of the Board on a part-time basis.

7. For the purpose of paragraph 3, "Pengrowth" includes all of its subsidiary entities.

8. Despite any determination made under paragraphs 3 through 7 above, an individual who

(a) accepts, directly or indirectly, any consulting, advisory or other compensatory fee from Pengrowth or any subsidiary entity of Pengrowth, other than as remuneration for acting in his or her capacity as a member of the Board or any Board committee, or as a part-time chair or vice-chair of the Board or any Board committee; or

(b) is an affiliated entity of Pengrowth or any of its subsidiary entities,

is considered to have a material relationship with Pengrowth.

9. For the purposes of paragraph 8, the indirect acceptance by an individual of any consulting, advisory or other compensatory fee includes acceptance of a fee by

(a) an individual's spouse, minor child or stepchild, or a child or stepchild who shares the individual's home; or

(b) an entity in which such individual is a partner, member, an officer such as a managing director occupying a comparable position or executive officer, or occupies a similar position (except limited partners, non-managing members and those occupying similar positions who, in each case, have no active role in providing services to the entity) and which provides accounting, consulting, legal, investment banking or financial advisory services to Pengrowth or any subsidiary entity of Pengrowth.

10. For the purposes of paragraph 8, compensatory fees do not include the receipt of fixed amounts of compensation under a retirement plan (including deferred compensation) for prior service with Pengrowth if the compensation is not contingent in any way on continued service.

Standard of "Financial Literacy"

An individual is financially literate if he or she has the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of the issues that can reasonably be expected to be raised by Pengrowth's financial statements.

Schedule "B"

Excerpts from Rule 10A-3 of the Securities and Exchange Act of 1934

Standard of "Independence"

b. *Required standards.*

1. *Independence*.

i. Each member of the audit committee must be a member of the board of directors of the listed issuer, and must otherwise be independent; provided that, where a listed issuer is one of two dual holding companies, those companies may designate one audit committee for both companies so long as each member of the audit committee is a member of the board of directors of at least one of such dual holding companies.

ii. *Independence requirements for non-investment company issuers.* In order to be considered to be independent for purposes of this paragraph (b)(1), a member of an audit committee of a listed issuer that is not an investment company may not, other than in his or her capacity as a member of the audit committee, the board of directors, or any other board committee:

A. Accept directly or indirectly any consulting, advisory, or other compensatory fee from the issuer or any subsidiary thereof, provided that, unless the rules of the national securities exchange or national securities association provide otherwise, compensatory fees do not include the receipt of fixed amounts of compensation under a retirement plan (including deferred compensation) for prior service with the listed issuer (provided that such compensation is not contingent in any way on continued service); or

B. Be an affiliated person of the issuer or any subsidiary thereof.

e. *Definitions*. Unless the context otherwise requires, all terms used in this section have the same meaning as in the Act. In addition, unless the context otherwise requires, the following definitions apply for purposes of this section:

1.

i. The term *affiliate* of, or a person *affiliated* with, a specified person, means a person that directly, or indirectly through one or more intermediaries, controls, or is controlled by, or is under common control with, the person specified.

ii.

A. A person will be deemed not to be in control of a specified person for purposes of this section if the person:

1. Is not the beneficial owner, directly or indirectly, of more than 10% of any class of voting equity securities of the specified person; and

2. Is not an executive officer of the specified person.

B. Paragraph (e)(1)(ii)(A) of this section only creates a safe harbor position that a person does not control a specified person. The existence of the safe harbor does not create a presumption in any way that a person exceeding the ownership requirement in paragraph (e)(1)(ii)(A)(1) of this section controls or is otherwise an affiliate of a specified person.

iii. The following will be deemed to be affiliates:

A. An executive officer of an affiliate;

B. A director who also is an employee of an affiliate;

C. A general partner of an affiliate; and

D. A managing member of an affiliate.

iv. For purposes of paragraph (e)(1)(i) of this section, dual holding companies will not be deemed to be affiliates of or persons affiliated with each other by virtue of their dual holding company arrangements with each other, including where directors of one dual holding company are also directors of the other dual holding company, or where directors of one or both dual holding companies are also directors of the businesses jointly controlled, directly or indirectly, by the dual holding companies (and, in each case, receive only ordinary-course compensation for serving as a member of the board of directors, audit committee or any other board committee of the dual holding companies or any entity that is jointly controlled, directly or indirectly, by the dual holding companies).

4. The term control (including the terms controlling, controlled by and under common control with) means the possession, direct or indirect, of the power to direct or cause the direction of the management and policies of a person, whether through the ownership of voting securities, by contract, or otherwise.

8. The term indirect acceptance by a member of an audit committee of any consulting, advisory or other compensatory fee includes acceptance of such a fee by a spouse, a minor child or stepchild or a child or stepchild sharing a home with the member or by an entity in which such member is a partner, member, an officer such as a managing director occupying a comparable position or executive officer, or occupies a similar position (except limited partners, non-managing members and those occupying similar positions who, in each case, have no active role in providing services to the entity) and which provides accounting, consulting, legal, investment banking or financial advisory services to the issuer or any subsidiary of the issuer.

Schedule "C"

Excerpts from Section 303A.00 of the New York Stock Exchange Listed Company Manual

303A.02 "Independence" Tests

The NYSE Listed Company Manual contains the following provisions regarding the independence requirements of members of the audit committee:

(a) (i) No director qualifies as "independent" unless the board of directors affirmatively determines that the director has no material relationship with the listed company (either directly or as a partner, shareholder or officer of an organization that has a relationship with Pengrowth).

(ii) In addition, in affirmatively determining the independence of any director who will serve on the compensation committee of the listed company's board of directors, the board of directors must consider all factors specifically relevant to determining whether a director has a relationship to the listed company which is material to that director's ability to be independent from management in connection with the duties of a compensation committee member, including, but not limited to:

(A) the source of compensation of such director, including any consulting, advisory or other compensatory fee paid by the listed company to such director; and

(B) whether such director is affiliated with the listed company, a subsidiary of the listed company or an affiliate of a subsidiary of the listed company.

(b) In addition, a director is not independent if:

(i) The director is, or has been within the last three years, an employee of the listed company, or an immediate family member is, or has been within the last three years, an executive officer, of the listed company.

(ii) The director has received, or has an immediate family member who has received, during any twelve-month period within the last three years, more than $120,000 in direct compensation from the listed company, other than director and committee fees and pension or other forms of deferred compensation for prior service (provided such compensation is not contingent in any way on continued service).

(iii) (A) The director is a current partner or employee of a firm that is the listed company's internal or external auditor; (B) the director has an immediate family member who is a current partner of such a firm; (C) the director has an immediate family member who is a current employee of such a firm and personally works on the listed company's audit; or (D) the director or an immediate family member was within the last three years a partner or employee of such a firm and personally worked on the listed company's audit within that time.

(iv) The director or an immediate family member is, or has been within the last three years, employed as an executive officer of another company where any of the listed company's present executive officers at the same time serves or served on that company's compensation committee.

(v) The director is a current employee, or an immediate family member is a current executive officer, of a company that has made payments to, or received payments from, the listed company for property or services in an amount which, in any of the last three fiscal years, exceeds the greater of $1 million, or 2% of such other company's consolidated gross revenues.

General Commentary to Section 303A.02(b):

An "immediate family member" includes a person's spouse, parents, children, siblings, mothers and fathers-in-law, sons and daughters-in-law, brothers and sisters-in-law, and anyone (other than domestic employees) who shares such person's home. When applying the look-back provisions in Section 303A.02(b), listed companies need not consider individuals who are no longer immediate family members as a result of legal separation or divorce, or those who have died or become incapacitated.

In addition, references to the "listed company" or "company" include any parent or subsidiary in a consolidated group with the listed company or such other company as is relevant to any determination under the independent standards set forth in this Section 303A.02(b).

For purposes of Section 303A, the term "executive officer" has the same meaning specified for the term "officer" in Rule 16a-1(f) under the Securities Exchange Act of 1934 as follows:

> The term "officer" shall mean an issuer's president, principal financial officer, principal accounting officer (or, if there is no such accounting officer, the controller), any vice-president of the issuer in charge of a principal business unit, division or function (such as sales, administration or finance), any other officer who performs a policy-making function, or any other person who performs similar policy-making functions for the issuer. Officers of the issuer's parent(s) or subsidiaries shall be deemed officers of the issuer if they perform such policy-making functions for the issuer. In addition, when the issuer is a limited partnership, officers or employees of the general partner(s) who perform policy-making functions for the limited partnership are deemed officers of the limited partnership. When the issuer is a trust, officers or employees of the trustee(s) who perform policy-making functions for the trust are deemed officers of the trust.

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