

# 2016

## PENGROWTH ENERGY CORPORATION

### ANNUAL INFORMATION FORM

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**FEBRUARY 28, 2017**

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Unless otherwise indicated, all of the information provided in this Annual Information Form is as at December 31, 2016

# GLOSSARY OF TERMS AND ABBREVIATIONS

The following terms in this Annual Information Form have the meanings set forth below:

## Corporate

"**6.25% Series B Convertible Debentures**" means the \$126.6 million aggregate principal amount of 6.25 percent convertible unsecured subordinated debentures of the Corporation due March 31, 2017, which are convertible at the option of the holder, at any time, into fully paid Common Shares at a conversion price of \$11.5116 per Common Share;

"**2007 Note Purchase Agreements**" means, collectively, the separate and several note purchase agreements each dated July 26, 2007 among us and the purchasers listed therein, as amended;

"**2007 Senior Notes**" means the US\$400 million of senior unsecured notes issued under the 2007 Note Purchase Agreements;

"**2008 Note Purchase Agreements**" means, collectively, the separate and several note purchase agreements dated August 21, 2008 among us and the purchasers listed therein, as amended;

"**2008 Senior Notes**" means the US\$285 million and \$15 million of senior unsecured notes collectively issued under the 2008 Note Purchase Agreements;

"**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 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 of senior unsecured notes collectively issued under the 2012 Note Purchase Agreements;

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

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

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

"**Common Shares**" means our common shares;

"**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 \$1.0 billion Amended and Restated Credit Agreement dated March 30, 2015 among Pengrowth and a syndicate of eleven financial institutions, as amended by amending agreements dated December 10, 2015 and February 9, 2017;

"**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 2007 Senior Notes, the 2008 Senior Notes, the 2010 Senior Notes and the 2012 Senior Notes.

## Engineering

"**abandonment 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;

"**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 fifty percent confidence level;

"**Bitumen**" means a naturally occurring solid or semi-solid hydrocarbon: (a) consisting of 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;

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

"**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;

"**Company Interest**" is equal to our gross interest plus Pengrowth's 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;

"**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, Calgary, Alberta;

"**GLJ Report**" refers to the reserve report prepared by GLJ, dated February 28, 2017 with an effective date of December 31, 2016;

"**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 °API and less than or equal to 22.3 °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;

"**light crude oil**" means crude oil with a relative density greater than 31.1 °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 ninety percent confidence level;

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

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

"**natural gas liquids**" 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;

"**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;

"**Remaining Reserve Life**" refers to the expected productive life of the property or fifty years, whichever is less;

"**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;

"**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\$**" refers to Canadian dollars;

"**CO<sub>2</sub>**" 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<sub>2</sub>S**" refers to hydrogen sulphide gas;

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

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

"**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\$**" 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.

**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. In addition, 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.**

## CONVERSION

In this Annual Information Form, measurements are given in standard imperial or metric units only. 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

## PRESENTATION OF OUR FINANCIAL INFORMATION

Financial information in this Annual Information Form 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 Annual Information Form 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 Annual Information Form in accordance with Canadian disclosure requirements, we have disclosed in this Annual Information Form 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 Annual Information Form 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 — 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](http://www.sec.gov).

## FORWARD-LOOKING STATEMENTS

This Annual Information Form contains forward-looking statements within the meaning of securities laws, including the "safe harbour" provisions of Canadian securities legislation and the United States *Private Securities Litigation Reform Act of 1995*. Forward-looking information is 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 in this Annual Information Form include, but are not limited to: business strategy and strengths, goals, focus and the effects thereof, capital expenditures, reserves, resources, reserve life indices, estimated production, remaining producing reserves lives, operating expenses, asset retirement obligations, royalty rates, net present values of Future Net Revenue from reserves, commodity prices and costs, dividend policy, exchange rates, development plans and programs, Future Development Costs and the funding thereof, tax horizon, future income taxes, Lindbergh and Selina expansion and development plans, Bernadet development plans, abandonment and reclamation costs and expiring acreage. Statements relating to reserves and resources are 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.

Forward-looking statements and information are based on our current beliefs 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 exchange rates, the proceeds of anticipated divestitures, the amount of future cash dividends paid by the Corporation, the cost of expanding our property holdings, our ability to obtain equipment in a timely 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 considers these assumptions to be reasonable based on information currently available to it, they may prove to be incorrect.

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 oil and gas prices; production and development costs and capital expenditures; the imprecision of reserve estimates and estimates of recoverable quantities of oil, natural gas and liquids; unforeseen operating problems; pipeline or delivery 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; defaults by third party operators; unforeseen title defects; fluctuations in foreign currency and exchange rates; inadequate insurance coverage; counterparty risk; compliance with environmental laws and regulations; changes in tax and royalty laws; our ability to access external sources of debt and equity capital; and the implementation of GHG emissions legislation. Further information regarding these factors may be found under the heading "*Risk Factors*" in this Annual Information Form, under the heading "*Business Risks*" in our Management's Discussion and Analysis for the year ended December 31, 2016, and in our most recent consolidated financial statements, management information circular, quarterly reports, material change reports and news releases.

Readers are cautioned that the foregoing list of 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 Annual Information Form 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 Annual Information Form are expressly qualified by this cautionary statement.

# ■ PENGROWTH ENERGY CORPORATION

## INTRODUCTION

The Corporation is engaged in the development, production and acquisition of, and the exploration for, oil and natural gas reserves in the provinces of Alberta, British Columbia, Saskatchewan and Nova Scotia. The Corporation is the successor to Pengrowth Energy Trust.

The Corporation was originally 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 2100, 222 – 3rd Avenue S.W., Calgary, Alberta, Canada, T2P 0B4.

## GENERAL DEVELOPMENT OF THE BUSINESS

### Recent Developments

On February 21, 2017, we announced that we will: (i) prepay US\$300 million of the 2007 Senior Notes; and (ii) redeem \$126.6 million of our 6.25% Series B Convertible Debentures on maturity, with cash on hand on March 30, 2017.

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 reflects our plan to spend \$125 million in 2017.

On January 6, 2017, we completed the sale of a four percent non-convertible gross overriding royalty on our Lindbergh assets and an interest in certain proprietary seismic for aggregate cash consideration of \$250 million. The four percent overriding royalty would represent a 10.7 percent decrease (at a ten percent discount rate) in the December 31, 2016 P+P net present value of future net revenue for Lindbergh which is anticipated to be reflected in the next Lindbergh reserve update.

### Three Year Historical Overview

#### **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 December 14, 2016, we announced that we had entered into a definitive agreement for the sale of a four percent non-convertible gross overriding royalty interest on our Lindbergh thermal project and an interest in certain proprietary seismic for \$250 million aggregate cash consideration.

On October 6, 2016, we announced a 21 percent increase in our P+P reserves at our Lindbergh thermal project and a corresponding 63 percent 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 March 23, 2016, Mr. Seymour Schulich announced that he had acquired beneficial ownership or control of an aggregate of 80,000,000 Common Shares representing 14.7 percent of the then issued and outstanding Common Shares. Over the remainder of 2016, Mr. Schulich made several additional acquisitions. In his most recent filing dated February 9, 2017, Mr. Schulich announced that he beneficially owns or controls 109,000,000 Common Shares representing 19.90 percent of the then issued and outstanding Common Shares.

On February 25, 2016, we announced the launch of a normal course issuer bid for up to 10 percent 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.

## **2015**

On December 1, 2015, our 5.46 percent £50,000,000 term notes matured and were repaid.

On December 10, 2015, we amended our Credit Facility by increasing the maximum permitted Senior Debt to Total Capitalization ratio from 50 percent to 55 percent. This amendment was obtained to align this covenant between our Credit Agreement and various note purchase agreements which already allowed a maximum Senior Debt to Total Capitalization ratio of 55 percent. All other material terms and conditions remained unchanged.

On November 30, 2015, we completed the sale of our non-core Jenner assets in southeastern Alberta for cash consideration of \$77.6 million (after closing adjustments).

On November 3, 2015, we reported our third quarter financial results including a non-cash, after-tax impairment charge of \$375 million.

On October 30, 2015, we completed the sale of our non-core Bodo property in eastern Alberta for \$86.7 million (after closing adjustments).

On October 29, 2015, we announced the receipt of notification from the NYSE of non-compliance with its 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 September 1, 2015, we announced a change to our dividend policy, moving to a quarterly payment at a rate of \$0.01 per share per quarter and suspending the dividend reinvestment and optional common share purchase plan.

On June 8, 2015, we reported that production from our Lindbergh thermal project exceeded the project's nameplate capacity of 12,500 bbl/d.

On May 12, 2015, we announced the appointments of Steve De Maio as Senior Vice President, Thermal Operations and Randy Steele as Senior Vice President, Conventional Operations.

On May 11, 2015, our 4.67 percent US\$71.5 million senior notes, series A matured and were repaid.

On April 28, 2015, we announced the departures of Marlon McDougall and James Causgrove who were our Chief Operating Officer and Senior Vice President, Operations, respectively.

On April 14, 2015, we announced the appointment of Jamie Sokalsky to our Board.

On March 30, 2015 we renewed and extended our Credit Facility from July 26, 2017 to March 31, 2019. At this time we also amended the maximum permitted Senior Debt to EBITDA ratio from 3.0 to 3.5 and the Total Debt to EBITDA ratio from 3.5 to 4.0.

On February 26, 2015, we announced our 2014 year end results including a non-cash, after-tax impairment charge of approximately \$858 million.

On January 21, 2015, we announced our 2015 capital program and provided guidance on 2015 expected production and costs. We also announced a reduction in our dividend from \$0.04 per share per month to \$0.02 per share per month beginning with the dividend payable on March 16, 2015. Our 2015 capital budget reflected our plan to spend between \$220 million and \$240 million in 2015.

## **2014**

On December 31, 2014, our \$97.9 million principal amount 6.25 percent series A convertible debentures matured.

On December 15, 2014, we announced the commencement of steam injection at our Lindbergh commercial project.

On December 1, 2014, we announced the appointment of Margaret Byl to our Board.

On November 5, 2014, we acquired a 100 percent interest in 32.6 sections of Montney prospective lands at Bernadet in northeastern British Columbia for \$123.6 million.

On June 24, 2014, we announced a reserve evaluation update, effective May 31, 2014, with respect to our Lindbergh property, noting a 24 percent increase in Proved Reserves and a 61 percent increase in Total Proved Plus Probable Reserves from December 31, 2013.

On January 24, 2014, we amended our Credit Facility by increasing the maximum permitted consolidated Senior Debt to EBITDA ratio from 3.0 to 3.5 and the consolidated Total Debt to EBITDA ratio from 3.5 to 4.0 until December 31, 2015.

On January 16, 2014, we announced our 2014 capital program and provided guidance on 2014 expected production and costs. Our 2014 capital budget reflected our plan to spend between \$700 million and \$730 million in 2014 including \$365 million at Lindbergh.

# DESCRIPTION OF OUR BUSINESS

## GENERAL

We are engaged in the development, production and acquisition of, and the exploration for, oil and natural gas reserves in the provinces of Alberta, British Columbia, Saskatchewan and Nova Scotia. 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. We believe we have the skills and financial capacity to develop our opportunities. A key factor affecting our finances is commodity prices over which we have no control.

As at December 31, 2016, we had 427 permanent employees.

## BUSINESS STRATEGY

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

Our operational expertise is in the WCSB. We rely on our expertise to partially offset production declines in our mature oil and gas properties as well as develop new production in less mature oil and gas properties. We continue to deploy our significant expertise in horizontal well multi-stage fracturing technology and waterflood optimization. Additionally, we have assembled a highly skilled team experienced in thermal development. Our inventory of undeveloped land and opportunities on our properties provide future drilling opportunities for the short-term and mid-term. In the mid-term, we anticipate continuing to develop our thermal project at Lindbergh, with the potential for 40,000 to 50,000 bbl/d of bitumen, as well as our light crude oil and liquids-rich gas properties in the Greater Olds/Garrington and Swan Hills areas and our significant natural gas operations at Groundbirch and Bernadet. See additional details on these properties under "Operational Information – Principal Producing Properties" below.

For 2017, we have established a \$125 million capital spending level that reflects the current commodity price environment, the Corporation's 2017 debt maturities and which will be reviewed following any material asset divestitures in 2017. Our 2017 capital budget represents a consistent approach with our 2016 capital budget and is focused on safety and the maintenance and integrity of existing assets.

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.

## OPERATIONAL INFORMATION

### PRINCIPAL PRODUCING PROPERTIES

The following table summarizes our principal producing properties as of December 31, 2016 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, 2016. The table also contains our average daily production of oil, bitumen, natural gas, shale gas and NGL for the year ended December 31, 2016.

**Summary of Company Interest at December 31, 2016<sup>(1)</sup>**  
**(Forecast Prices and Costs)<sup>(2)</sup>**

Field	P+P Reserves (Mboe <sup>(3)</sup> )	Remaining Reserve Life (years)	P+P Reserve Life Index (years)	P+P Value Before Tax Discounted at 10% <sup>(4)</sup> (\$MM)	2016 Oil Production (bbl/d)	2016 Bitumen Production (bbl/d)	2016 Gas Production (MMcf/d)	2016 Shale Gas Production (MMcf/d)	2016 NGL Production (bbl/d)	2016 Total Production (BOE/d <sup>(3)</sup> )
Lindbergh	317,905	29	59.4	2,721	-	15,296	-	-	-	15,296
Greater Olds/ Garrington Area	69,783	46	15.9	625	2,644	-	44.4	-	3,306	13,352
Swan Hills Area	51,296	50	12.9	596	6,576	-	6.8	-	2,432	10,137
Groundbirch	117,106	50	189.8	321	-	-	-	12.5	-	2,083
<b>Subtotal</b>	<b>556,090</b>	<b>50</b>	<b>38.8</b>	<b>4,263</b>	<b>9,220</b>	<b>15,296</b>	<b>51.2</b>	<b>12.5</b>	<b>5,738</b>	<b>40,868</b>
Remainder <sup>(5)</sup>	52,459	50	10.9	272	2,805	-	68.1	-	2,025	16,190
<b>Total</b>	<b>608,549</b>	<b>50</b>	<b>31.8</b>	<b>4,535</b>	<b>12,025</b>	<b>15,296</b>	<b>119.3</b>	<b>12.5</b>	<b>7,763</b>	<b>57,058</b>

#### 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 58 other properties.

## Lindbergh

The Lindbergh thermal property is located approximately 420 kilometres north east of Calgary, Alberta and 50 kilometres south of Bonnyville, Alberta. We have a 100 percent 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). Our Lindbergh area assets include our 100 percent owned Muriel Lake property located approximately eight kilometres to the north east of the Lindbergh lease and is comprised of an additional 6,400 net acres (10 sections). The Corporation has drilled and evaluated 82 delineation wells since acquiring the Lindbergh property in 2004. In addition, 116 existing wells have been used in the geological evaluation including 10 on the Muriel Lake property. Additionally, 64 square kilometres of three dimensional seismic along with 105 kilometres of two dimensional seismic has been shot and evaluated.

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 pilot facility, well pad and two SAGD well pairs were constructed, drilled and completed in December 2011. The wells were drilled from a single pad with each having an effective horizontal well length of approximately 840 metres within the bitumen-bearing Lloydminster formation. Both well pairs encountered high quality reservoir throughout with no lean zones or shale barriers in any of the well bores. We began steam injection into the SAGD pilot project in early February 2012 and results have outperformed expectations since that time.

Based on the excellent pilot results, Pengrowth developed a commercial project with a first phase design capacity of 12,500 bbl/d of bitumen (including the pilot area) with an expected project life of 29 years. In July 2013, the project received regulatory approval to proceed under the EPEA application number 1713445. Construction commenced in August 2013 on the commercial project. The project achieved first steam in December 2014. This first commercial phase is comprised of a central processing facility ("**CPF**"), three additional well pads, surface pipelines, 20 new well pairs, a 15 MW cogeneration plant and other associated infrastructure. The drilling of the additional wells went as anticipated and the characteristics of the wells as drilled were similar to those observed for the pilot well pairs.

Over the life of the 12,500 bbl/d commercial project, a total of 97 well pairs (including the 22 existing well pairs) are expected to be drilled from several central pad sites within the project area, recovering Proved Reserves of 146 MMbbl of bitumen remaining as of December 31, 2016. The production life for each individual well pair is expected to be eight to nine years. Under our development plan, as individual well pair production declines, additional well pairs would be drilled throughout the project area to maintain production.

With the Phase 2 expansion to 30,000 bbl/day of capacity, the project is expected to recover 318 MMbbl of Total Proved Plus Probable Reserves as of December 31, 2016, from a total of 266 well pairs, including the 22 existing well pairs, and 262 infill wells. The EPEA application for the first of these expansions to 30,000 bbl/d was approved on May 30, 2016. Given the strong results to-date, additional productivity is thought to be possible and anticipated from Phase 1 and Phase 2. In February 2017, Pengrowth submitted a scheme amendment application to increase Phase 2 production to an aggregate of 40,000 bbl/d when combined with the Phase 1 production. There is also potential for further expansion to attain 50,000 bbl/d over all the Pengrowth lands in the Lindbergh region.

As mentioned above under "*General Development of the Business - Recent Developments*" we recently sold a four percent 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 Annual Information Form.

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 50 kilometres south east of Bonnyville, Alberta. The proposed project is designed for an annual average production rate of 12,500 bbl/d of bitumen. It is a 50/50 joint venture between the Corporation and Koch. Koch is the operator of this project.

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

## Greater Olds/Garrington Area

Our Greater Olds/Garrington area is located approximately 100 kilometres north of Calgary, Alberta. Our interests in this area include a 100 percent ownership of the Olds Gas Field Unit No. 1. In addition, we have an 86 percent average Working Interest in the adjacent non-unit reserves. The Olds Gas Field Unit No. 1 produces sour natural gas from the Wabamun formation, with H<sub>2</sub>S concentrations ranging from less than one percent to 35 percent. The non-unit reserves are contained within formations from the Wabamun to the Edmonton group, and are predominantly sweet natural gas.

The Greater Olds/Garrington area is characterized by stacked reservoirs with multi-zone potential. Pengrowth has been exploiting several development opportunities over the past number of years in the Harmattan gas field, including the development of our liquids-rich (50 bbl/MMcf) Elkton gas play and more recently, the liquids-rich (100-120 bbl/MMcf) Mannville gas play and Elkton oil play.

We operate and own 100 percent of the sour gas processing plant at Olds, Alberta, which processes both our production and third party volumes. Third party volumes represent approximately 30 percent of the total volumes processed at the plant.

Pengrowth has a large contiguous land base in this area with approximately 480 gross sections with Cardium rights, averaging an approximately 46 percent Working Interest. In addition to the Cardium, other zones of interest in the area include the liquids-rich Mannville and Elkton formations. In 2016, Pengrowth focused capital spending on safety, integrity and maintenance activities, spending approximately \$10.7 million in the Greater Olds/Garrington area, drilling only 1 gross (0.15 net) Ellerslie well during the year.

The Harmattan gas field, within the Greater Olds/Garrington area, is located approximately 90 kilometres northwest of Calgary, Alberta. It is comprised of wells and pools in formations from the Wabamun to the Cardium, as well as two partner-operated Elkton units. The production is predominantly sweet liquids-rich natural gas and sweet oil with Working Interests averaging 65 percent in the non-unit lands (operated) and 25 percent in the partner-operated units.

### Swan Hills Area

We have varied Working Interests within the Swan Hills area in all of the key properties throughout this significant regional Beaverhill Lake resource base. These are both operated and non-operated, unit and non-unit properties in Judy Creek, Carson Creek, House Mountain, Deer Mountain, Swan Hills, South Swan Hills and Freeman. The properties are primarily located approximately 200 kilometres northwest of Edmonton, Alberta.

The two major operated properties in the area are:

- The Judy Creek Beaverhill Lake Unit and the Judy Creek West Beaverhill Lake Unit are both oil properties (together referred to as "**Judy Creek**"), where we have a 100 percent Working Interest in both. Judy Creek covers an area of approximately 38,300 acres, was discovered in 1959, placed on waterflood in 1962 and hydrocarbon miscible flood in 1985. We also have a 54.4 percent Working Interest in and operate the Judy Creek Gas Conservation Plant that services a number of other properties in the area including Swan Hills, Virginia Hills and South Swan Hills.
- Carson Creek is comprised of two Pengrowth operated units (one oil and one natural gas) covering approximately 46,200 acres. The Carson Creek North Beaverhill Lake Unit No. 1, in which we have a 90.6 percent Working Interest, was discovered in 1958 and the current waterflood was initiated in 1964. The Carson Creek Beaverhill Lake Unit No. 1, in which we have a 95.1 percent Working Interest, was discovered in 1958.

In 2016, as a result of depressed commodity prices, no development work was conducted in the Swan Hills area. Capital spending in 2016 was focused on safety, integrity and maintenance activities on the operated and partner operated properties, with a total year-end spend of approximately \$20.7 million (net).

### Groundbirch

Our Groundbirch property is located approximately 40 kilometres south west of Fort St. John, British Columbia and covers an area of 13,855 gross (12,536 net) acres. We have an average 90 percent Working Interest in these lands. At Groundbirch, we currently have 17 producing wells producing approximately 11.4 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.

The 2014 horizontal wells, which were completed with an increased number of fracture stages and more proppant per horizontal foot of well bore, continue to outperform initial type curve expectations and have demonstrated the effectiveness of current fracture techniques.

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

The Corporation's 100 percent owned Bernadet property is located approximately 125 kilometres north of Groundbirch. Bernadet is a 37 section Montney play that is believed to contain a significant liquids-rich Montney gas resource. The Corporation has entered into a long term relationship with the neighboring First Nations community and is developing plans for 3D seismic and initial drilling targeted for 2018.

## STATEMENT OF OIL AND GAS RESERVES AND RESERVES DATA

### 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, 2016 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, 2016 and the preparation date is January 21, 2017 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 Annual Information Form. All of our reserves are in Canada in the provinces of Alberta, British Columbia, Saskatchewan and Nova Scotia. In certain instances in this Annual Information Form, 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 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, 2016 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 Annual Information Form reflect the royalty programs in-place on December 31, 2016.

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 \$3 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 Annual Information Form as Appendices B and C, respectively.

Reserves Data (Forecast Prices and Costs)

**Summary of Oil and Gas Reserves as of December 31, 2016  
(Forecast Prices and Costs)<sup>(1)</sup>**

Reserves Category	Light Crude Oil and Medium Crude Oil			Heavy Crude Oil			Bitumen			Natural Gas Liquids		
	Company Interest (Mbbbl)	Gross Interest (Mbbbl)	Net Interest (Mbbbl)	Company Interest (Mbbbl)	Gross Interest (Mbbbl)	Net Interest (Mbbbl)	Company Interest (Mbbbl)	Gross Interest (Mbbbl)	Net Interest (Mbbbl)	Company Interest (Mbbbl)	Gross Interest (Mbbbl)	Net Interest (Mbbbl)
<b>Proved Reserves</b>												
Proved Developed Producing	31,129	31,060	25,883	2	2	2	16,258	16,258	15,565	18,484	18,457	13,998
Proved Developed Non-Producing	3,818	3,817	3,034	-	-	-	-	-	-	1,222	1,222	986
Proved Undeveloped	5,232	5,232	4,649	-	-	-	130,007	130,007	102,511	4,760	4,760	4,148
<b>Total Proved Reserves</b>	<b>40,179</b>	<b>40,110</b>	<b>33,565</b>	<b>2</b>	<b>2</b>	<b>2</b>	<b>146,265</b>	<b>146,265</b>	<b>118,077</b>	<b>24,466</b>	<b>24,439</b>	<b>19,132</b>
Probable Reserves	16,853	16,828	13,762	1	1	1	171,640	171,640	132,222	11,643	11,634	9,617
<b>Total Proved Plus Probable Reserves</b>	<b>57,032</b>	<b>56,938</b>	<b>47,327</b>	<b>4</b>	<b>4</b>	<b>4</b>	<b>317,905</b>	<b>317,905</b>	<b>250,299</b>	<b>36,109</b>	<b>36,073</b>	<b>28,748</b>

Reserves Category	Conventional Natural Gas			Shale Gas			Coal Bed Methane			Total Oil Equivalent Basis <sup>(2)</sup>		
	Company Interest (MMcf)	Gross Interest (MMcf)	Net Interest (MMcf)	Company Interest (MMcf)	Gross Interest (MMcf)	Net Interest (MMcf)	Company Interest (MMcf)	Gross Interest (MMcf)	Net Interest (MMcf)	Company Interest (Mboe)	Gross Interest (Mboe)	Net Interest (Mboe)
<b>Proved Reserves</b>												
Proved Developed Producing	254,707	253,665	219,995	30,815	30,815	28,577	12,194	11,963	11,247	115,493	115,185	98,752
Proved Developed Non-Producing	15,093	15,087	12,893	-	-	-	1,511	1,511	1,377	7,807	7,805	6,398
Proved Undeveloped	43,240	43,240	38,807	86,677	86,677	74,875	5,128	5,093	4,873	162,506	162,500	131,067
<b>Total Proved Reserves</b>	<b>313,039</b>	<b>311,992</b>	<b>271,695</b>	<b>117,492</b>	<b>117,492</b>	<b>103,452</b>	<b>18,832</b>	<b>18,567</b>	<b>17,497</b>	<b>285,806</b>	<b>285,491</b>	<b>236,217</b>
Probable Reserves	141,867	141,498	124,628	585,146	585,146	489,153	8,616	8,546	7,550	322,743	322,635	259,157
<b>Total Proved Plus Probable Reserves</b>	<b>454,906</b>	<b>453,490</b>	<b>396,323</b>	<b>702,638</b>	<b>702,638</b>	<b>592,605</b>	<b>27,448</b>	<b>27,113</b>	<b>25,047</b>	<b>608,549</b>	<b>608,126</b>	<b>495,374</b>

**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, 2016  
Before and After Income Taxes (Forecast Prices and Costs)<sup>(1)</sup>**

Reserves Category	Before Income Taxes Discounted at (%/year) - \$MM					Unit Value Before Income Tax Discounted at 10%/year <sup>(2)(3)</sup>	
	0%	5%	10%	15%	20%	\$/BOE	\$/McfGE
<b>Proved Reserves</b>							
Proved Developed Producing	1,852	1,465	1,220	1,054	935	12.35	2.06
Proved Developed Non-Producing	132	100	79	64	54	12.34	2.06
Proved Undeveloped	4,376	2,035	1,109	675	442	8.46	1.41
<b>Total Proved Reserves</b>	<b>6,361</b>	<b>3,601</b>	<b>2,408</b>	<b>1,794</b>	<b>1,430</b>	<b>10.19</b>	<b>1.70</b>
Probable Reserves	7,437	3,826	2,128	1,250	762	8.21	1.37
<b>Total Proved Plus Probable Reserves</b>	<b>13,798</b>	<b>7,426</b>	<b>4,535</b>	<b>3,044</b>	<b>2,193</b>	<b>9.16</b>	<b>1.53</b>

Reserves Category	After Income Taxes Discounted at (%/year) <sup>(4)</sup> - \$MM				
	0%	5%	10%	15%	20%
<b>Proved Reserves</b>					
Proved Developed Producing	1,852	1,465	1,220	1,054	935
Proved Developed Non-Producing	132	100	79	64	54
Proved Undeveloped	3,332	1,778	1,034	646	425
<b>Total Proved Reserves</b>	<b>5,317</b>	<b>3,343</b>	<b>2,333</b>	<b>1,764</b>	<b>1,414</b>
Probable Reserves	5,091	2,634	1,456	847	509
<b>Total Proved Plus Probable Reserves</b>	<b>10,408</b>	<b>5,977</b>	<b>3,789</b>	<b>2,611</b>	<b>1,923</b>

**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 – "Operational Information - Statement of Oil and Gas Reserves and Reserves Data – 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, 2016  
(Forecast Prices and Costs)<sup>(1)</sup> (\$MM)**

Reserves Category	Revenue	Royalties <sup>(2)</sup>	Operating Costs	Development Costs	Abandonment and Reclamation Costs <sup>(3)</sup>	Future Net Revenue Before Income Taxes	Income Tax	Future Net Revenue After Income Taxes
Total Proved	18,185	3,438	5,718	1,980	689	6,361	1,044	5,317
Total Proved Plus Probable	37,016	7,419	9,543	5,234	1,022	13,798	3,390	10,408

**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 "Operational 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, 2016**  
**(Forecast Prices and Costs)<sup>(1)</sup>**

Reserves Category	Product Type	Future Net Revenue Before Income Taxes (discounted at 10%/year)	Unit Value <sup>(4)(5)</sup>	
		(\$MM)	(\$/BOE)	(\$/McfGE)
Total Proved	Light Crude Oil and Medium Crude Oil (including solution gas and other by-products) <sup>(2)</sup>	742	14.58	2.43
	Heavy Crude Oil (including solution gas and other by-products) <sup>(2)</sup>	-	14.75	2.46
	Bitumen	1,196	10.13	1.69
	Conventional Natural Gas (including by-products but excluding solution gas from oil wells) <sup>(3)</sup>	380	8.06	1.34
	Shale Gas	81	4.70	0.78
	Coal Bed Methane	9	2.95	0.49
	<b>Total</b>		<b>2,408</b>	<b>10.19</b>
Total Proved Plus Probable	Light Crude Oil and Medium Crude Oil (including solution gas and other by-products) <sup>(2)</sup>	1,036	13.93	2.32
	Heavy Crude Oil (including solution gas and other by-products) <sup>(2)</sup>	-	16.26	2.71
	Bitumen	2,586	10.33	1.72
	Conventional Natural Gas (including by-products but excluding solution gas from oil wells) <sup>(3)</sup>	525	7.75	1.29
	Shale Gas	376	3.81	0.63
	Coal Bed Methane	12	2.99	0.50
	<b>Total</b>		<b>4,535</b>	<b>9.16</b>

**Notes:**

- (1) Forecast prices are shown under the heading "Pricing Assumptions".
- (2) NGL associated with the production of solution gas are included as a by-product.
- (3) NGL associated with the production of natural gas are included as a by-product.
- (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, 2016  
(Constant Prices and Costs)<sup>(1)</sup>**

Reserves Category	Light Crude Oil and Medium Crude Oil			Heavy Crude Oil			Bitumen			Natural Gas Liquids		
	Company Interest	Gross Interest	Net Interest	Company Interest	Gross Interest	Net Interest	Company Interest	Gross Interest	Net Interest	Company Interest	Gross Interest	Net Interest
	(Mbbbl)	(Mbbbl)	(Mbbbl)	(Mbbbl)	(Mbbbl)	(Mbbbl)	(Mbbbl)	(Mbbbl)	(Mbbbl)	(Mbbbl)	(Mbbbl)	(Mbbbl)
<b>Proved Reserves</b>												
Proved Developed Producing	25,108	25,058	22,745	2	2	2	14,124	14,124	13,890	13,914	13,898	10,684
Proved Developed Non-Producing	4,280	4,280	3,762	-	-	-	-	-	-	1,254	1,254	1,024
Proved Undeveloped	4,112	4,112	3,821	-	-	-	129,915	129,915	128,060	2,873	2,873	2,541
<b>Total Proved Reserves</b>	<b>33,500</b>	<b>33,450</b>	<b>30,328</b>	<b>2</b>	<b>2</b>	<b>2</b>	<b>144,039</b>	<b>144,039</b>	<b>141,949</b>	<b>18,041</b>	<b>18,025</b>	<b>14,249</b>
Probable Reserves	15,140	15,121	13,787	1	1	1	173,093	173,093	166,109	10,374	10,368	8,854
<b>Total Proved Plus Probable Reserves</b>	<b>48,639</b>	<b>48,571</b>	<b>44,115</b>	<b>3</b>	<b>3</b>	<b>3</b>	<b>317,132</b>	<b>317,132</b>	<b>308,058</b>	<b>28,415</b>	<b>28,393</b>	<b>23,103</b>

Reserves Category	Conventional Natural Gas			Shale Gas			Coal Bed Methane			Total Oil Equivalent Basis <sup>(2)</sup>		
	Company Interest	Gross Interest	Net Interest	Company Interest	Gross Interest	Net Interest	Company Interest	Gross Interest	Net Interest	Company Interest	Gross Interest	Net Interest
	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(Mboe)	(Mboe)	(Mboe)
<b>Proved Reserves</b>												
Proved Developed Producing	188,608	188,036	165,331	25,688	25,688	24,917	6,658	6,562	6,140	89,973	89,796	80,052
Proved Developed Non-Producing	12,026	12,027	10,544	-	-	-	722	722	652	7,659	7,659	6,652
Proved Undeveloped	27,010	27,009	24,702	84,434	84,434	79,477	-	-	-	155,473	155,473	151,786
<b>Total Proved Reserves</b>	<b>227,643</b>	<b>227,072</b>	<b>200,576</b>	<b>110,123</b>	<b>110,123</b>	<b>104,393</b>	<b>7,380</b>	<b>7,285</b>	<b>6,791</b>	<b>253,106</b>	<b>252,929</b>	<b>238,489</b>
Probable Reserves	116,171	116,004	104,603	568,167	568,167	515,769	2,275	2,265	2,105	313,043	312,989	292,497
<b>Total Proved Plus Probable Reserves</b>	<b>343,814</b>	<b>343,076</b>	<b>305,179</b>	<b>678,289</b>	<b>678,289</b>	<b>620,163</b>	<b>9,655</b>	<b>9,549</b>	<b>8,896</b>	<b>566,148</b>	<b>565,917</b>	<b>530,986</b>

**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, 2016  
Before and After Income Taxes (Constant Prices and Costs)<sup>(1)</sup>**

Reserves Category	Before Income Taxes Discounted at (%/year) - \$MM					Unit Value Before Income Taxes Discounted at 10%/year <sup>(2)(3)</sup>	
	0%	5%	10%	15%	20%	\$/BOE	\$/McfGE
<b>Proved Reserves</b>							
Proved Developed Producing	484	438	398	365	339	4.97	0.83
Proved Developed Non-Producing	41	36	31	27	23	4.73	0.79
Proved Undeveloped	585	260	112	35	(8)	0.74	0.12
<b>Total Proved Reserves</b>	<b>1,110</b>	<b>734</b>	<b>541</b>	<b>428</b>	<b>355</b>	<b>2.27</b>	<b>0.38</b>
Probable Reserves	1,321	597	224	25	(82)	0.76	0.13
<b>Total Proved Plus Probable Reserves</b>	<b>2,431</b>	<b>1,332</b>	<b>764</b>	<b>453</b>	<b>272</b>	<b>1.44</b>	<b>0.24</b>

Reserves Category	After Income Taxes Discounted at (%/year) <sup>(4)</sup> - \$MM				
	0%	5%	10%	15%	20%
<b>Proved Reserves</b>					
Proved Developed Producing	484	438	398	365	339
Proved Developed Non-Producing	41	36	31	27	23
Proved Undeveloped	585	260	112	35	(8)
<b>Total Proved Reserves</b>	<b>1,110</b>	<b>734</b>	<b>541</b>	<b>428</b>	<b>355</b>
Probable Reserves	1,321	597	224	25	(82)
<b>Total Proved Plus Probable Reserves</b>	<b>2,431</b>	<b>1,332</b>	<b>764</b>	<b>453</b>	<b>272</b>

**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 – "Operational Information - Statement of Oil and Gas Reserves and Reserves Data – 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, 2016  
(Constant Prices and Costs)<sup>(1)</sup> (\$MM)**

Reserves Category	Revenue	Royalties <sup>(2)</sup>	Operating Costs	Development Costs	Abandonment and Reclamation Costs <sup>(3)</sup>	Future Net Revenue Before Income Taxes	Income Tax	Future Net Revenue After Income Taxes
Total Proved	6,800	362	3,378	1,464	487	1,110	-	1,110
Total Proved Plus Probable	13,942	785	5,851	4,204	671	2,431	-	2,431

**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 "Operational 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, 2016**  
**(Constant Prices and Costs)<sup>(1)</sup>**

Reserves Category	Product Type	Future Net Revenue Before	Unit Value <sup>(4)(5)</sup>	
		Income Taxes (discounted at 10%/year)	(\$/BOE)	(\$/McfGE)
		(\$MM)		
Total Proved	Light Crude Oil and Medium Crude Oil (including solution gas and other by-products) <sup>(2)</sup>	252	5.57	0.93
	Heavy Crude Oil (including solution gas and other by-products) <sup>(2)</sup>	-	2.74	0.46
	Bitumen	197	1.39	0.23
	Conventional Natural Gas (including by-products but excluding solution gas from oil wells) <sup>(3)</sup>	81	2.47	0.41
	Shale Gas	12	0.71	0.12
	Coal Bed Methane	(1)	(1.19)	(0.20)
	<b>Total</b>		<b>541</b>	<b>2.27</b>
Total Proved Plus Probable	Light Crude Oil and Medium Crude Oil (including solution gas and other by-products) <sup>(2)</sup>	345	5.07	0.84
	Heavy Crude Oil (including solution gas and other by-products) <sup>(2)</sup>	-	4.49	0.75
	Bitumen	241	0.78	0.13
	Conventional Natural Gas (including by-products but excluding solution gas from oil wells) <sup>(3)</sup>	113	2.27	0.38
	Shale Gas	66	0.64	0.11
	Coal Bed Methane	(1)	(0.65)	(0.11)
	<b>Total</b>		<b>764</b>	<b>1.44</b>

**Notes:**

- (1) Constant prices are shown under the heading "Pricing Assumptions".
- (2) NGL associated with the production of solution gas are included as a by-product.
- (3) NGL associated with the production of natural gas are included as a by-product.
- (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 two percent 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, 2017 price forecast as referred to in the GLJ Report.

Year	Oil						Natural Gas	Natural Gas Liquids <sup>(1)</sup>			Inflation Rates <sup>(2)</sup> (%/year)	Exchange Rate <sup>(3)</sup> (US\$/Cdn\$)
	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 <sup>(5)</sup> (Cdn\$/bbl)	AECO Gas Price (Cdn\$/MMBtu)	Propane (Cdn\$/bbl)	Butane (Cdn\$/bbl)	Pentanes Plus (Cdn\$/bbl)		
2016 <sup>(4)</sup>	43.30	52.95	48.71	38.84	32.66	27.57	2.19	13.03	34.36	56.12	1.5	0.7550
2017	55.00	69.33	64.48	53.32	46.69	41.06	3.46	28.43	49.92	72.11	2.0	0.7500
2018	59.00	72.26	67.20	56.79	50.40	44.84	3.10	26.74	54.19	74.79	2.0	0.7750
2019	64.00	75.00	69.75	61.27	55.03	49.53	3.27	26.25	56.25	78.75	2.0	0.8000
2020	67.00	76.36	71.02	63.00	56.96	51.53	3.49	26.73	57.27	79.80	2.0	0.8250
2021	71.00	78.82	73.31	65.90	59.95	54.55	3.67	27.59	59.12	82.37	2.0	0.8500
2022	74.00	82.35	76.59	69.42	63.43	58.02	3.86	28.82	61.76	86.06	2.0	0.8500
2023	77.00	85.88	79.87	72.91	66.99	61.60	4.05	30.06	64.41	89.32	2.0	0.8500
2024	80.00	89.41	83.15	76.45	70.48	65.08	4.16	31.29	67.06	92.99	2.0	0.8500
2025	83.00	92.94	86.44	79.93	73.63	68.02	4.24	32.53	69.71	97.59	2.0	0.8500
2026	86.05	95.61	88.92	83.47	77.54	71.94	4.32	33.46	71.71	99.91	2.0	0.8500
thereafter	+2%/year	+2%/year	+2%/year	+2%/year	+2%/year	+2%/year	+2%/year	+2%/year	+2%/year	+2%/year	2.0	0.8500

#### 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) Actual average historical prices for 2016.
- (5) 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 2016 and were not escalated. In addition to the product prices, operating and capital costs have no inflationary increase. The constant prices are as follows:

Year	Oil						Natural Gas	Natural Gas Liquids <sup>(1)</sup>			Inflation Rate (%/year)	Exchange Rate (US\$/Cdn\$)
	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 <sup>(2)</sup> (Cdn\$/bbl)	AECO Gas Price (Cdn\$/MMBtu)	Propane (Cdn\$/bbl)	Butane (Cdn\$/bbl)	Pentanes Plus (Cdn\$/bbl)		
2017 and thereafter	42.65	52.12	47.89	38.02	31.85	26.37	2.18	11.38	33.61	55.27	0.0	0.7560

#### 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, 2016, 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 (Mbbbl)	Probable (Mbbbl)	Proved Plus Probable (Mbbbl)	Proved (Mbbbl)	Probable (Mbbbl)	Proved Plus Probable (Mbbbl)	Proved (Mbbbl)	Probable (Mbbbl)	Proved Plus Probable (Mbbbl)	Proved (Mbbbl)	Probable (Mbbbl)	Proved Plus Probable (Mbbbl)
<b>December 31, 2015</b>	<b>47,654</b>	<b>20,751</b>	<b>68,405</b>	<b>3,604</b>	<b>6,194</b>	<b>9,798</b>	<b>103,351</b>	<b>160,046</b>	<b>263,396</b>	<b>20,237</b>	<b>8,209</b>	<b>28,445</b>
Extensions & Improved Recovery	114	313	427	-	-	-	43,767	(22,835)	20,932	1,356	1,615	2,970
Infill Drilling	230	218	448	-	-	-	2,211	31,835	34,046	1,919	652	2,571
Technical Revisions	(2,200)	(2,599)	(4,799)	-	-	-	2,467	2,595	5,062	3,980	1,349	5,329
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-
Acquisitions	-	1	1	-	-	-	-	-	-	1	1	2
Dispositions	(1,141)	(1,512)	(2,654)	(3,272)	(6,193)	(9,465)	-	-	-	(221)	(72)	(292)
Economic Factors	(291)	(344)	(635)	-	-	-	-	-	-	(140)	(121)	(260)
Production	(4,257)	-	(4,257)	(329)	-	(329)	(5,531)	-	(5,531)	(2,692)	-	(2,692)
<b>December 31, 2016</b>	<b>40,110</b>	<b>16,828</b>	<b>56,938</b>	<b>2</b>	<b>1</b>	<b>4</b>	<b>146,265</b>	<b>171,640</b>	<b>317,905</b>	<b>24,439</b>	<b>11,634</b>	<b>36,073</b>

	Conventional Natural Gas			Shale Gas			Coal Bed Methane			Total Oil Equivalent Basis <sup>(1)</sup>		
	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)
<b>December 31, 2015</b>	<b>318,673</b>	<b>147,915</b>	<b>466,588</b>	<b>120,911</b>	<b>572,206</b>	<b>693,117</b>	<b>21,845</b>	<b>10,402</b>	<b>32,247</b>	<b>251,751</b>	<b>316,953</b>	<b>568,703</b>
Extensions & Improved Recovery	11,012	15,194	26,206	-	13,230	13,230	-	-	-	47,072	(16,170)	30,902
Infill Drilling	15,114	5,497	20,611	-	-	-	-	-	-	6,880	33,621	40,501
Technical Revisions	18,550	(13,140)	5,411	1,162	(289)	872	440	(1,425)	(985)	7,605	(1,130)	6,475
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-
Acquisitions	5	12	17	-	-	-	-	-	-	2	5	6
Dispositions	(8,870)	(12,029)	(20,899)	-	-	-	-	-	-	(6,113)	(9,781)	(15,894)
Economic Factors	(2,563)	(1,953)	(4,516)	12	-	12	(1,588)	(431)	(2,019)	(1,120)	(862)	(1,982)
Production	(39,927)	-	(39,927)	(4,593)	-	(4,593)	(2,131)	-	(2,131)	(20,585)	-	(20,585)
<b>December 31, 2016</b>	<b>311,994</b>	<b>141,497</b>	<b>453,490</b>	<b>117,492</b>	<b>585,146</b>	<b>702,638</b>	<b>18,567</b>	<b>8,546</b>	<b>27,113</b>	<b>285,491</b>	<b>322,635</b>	<b>608,126</b>

#### 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 barrel of oil.

At December 31, 2016, Company Interest Total Proved Plus Probable Reserves at forecast prices and costs were 608.5 MMboe as compared to 569.1 MMboe reported at year end 2015. The following additional GLJ reserves reconciliation is presented for year end December 31, 2016.

### Company Interest Reserves Reconciliation on Total Oil Equivalent Basis – Mboe<sup>(1)</sup> (Forecast Prices and Costs)

	Proved Developed Producing Reserves	Total Proved Reserves	Total Proved Plus Probable Reserve
<b>December 31, 2015</b>	<b>137,117</b>	<b>252,060</b>	<b>569,126</b>
Extensions & Improved Recovery	-	47,072	30,902
Infill Drilling	-	6,880	40,501
Technical Revisions	3,240	7,913	6,781
Discoveries	-	-	-
Acquisitions	2	4	6
Dispositions	(3,167)	(6,113)	(15,894)
Economic Factors	(816)	(1,126)	(1,990)
Production	(20,883)	(20,883)	(20,883)
<b>December 31, 2016</b>	<b>115,493</b>	<b>285,806</b>	<b>608,549</b>

#### 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.

Significant factors bearing on the reserves reconciliation were as follows:

- Net reserve changes from drilling activity, improved recovery, technical revisions and economic factors replaced 290 percent and 365 percent of 2016 production for Proved Reserves and Total Proved Plus Probable Reserves, respectively. Based on all changes, including acquisitions and dispositions, reserve replacement was 261 percent and 289 percent for Proved Reserves and Proved Plus Probable Reserves, respectively.
- New reserve additions for development activity during 2016 amounted to 54.0 MMboe of Proved Reserves and 71.4 MMboe of Total Proved Plus Probable Reserves. The most significant addition occurred in our Lindbergh oil sands property where regulatory approval of the Phase 2 expansion allowed us to book Proved Reserves beyond the initial Phase 1 development area. Additionally, based on ongoing technical analysis and our plan for development, Probable Reserves were booked for infill drilling and in an area of the Lindbergh pool partially drained by an earlier cyclic steam stimulation development. Other additions were for infill drilling and drilling extensions mainly in the Ellerslie play throughout the Harmattan/Garrington fairway where we hold an extensive land position.
- Technical revisions resulted in a net increase of 7.9 MMboe of Proved Reserves and 6.8 MMboe of Total Proved Plus Probable Reserves. This was primarily from performance improvements at Lindbergh and various properties in the Olds/Garrington area. The positive technical revisions were offset by reserve decreases due to economic factors relating to lower forecast product prices compared to last year end. The decrease due to economic factors is estimated to be 1.1 MMboe and 2.0 MMboe for Proved Reserves and Total Proved Plus Probable Reserves, respectively.
- Dispositions of non-core assets in Alberta, British Columbia and Saskatchewan resulted in a decrease of 6.1 MMboe and 15.9 MMboe of Proved Reserves and Total Proved Plus Probable Reserves, respectively, and included Tangleflags, Sukunka, Pine Creek and Sawn Lake.

## 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. Other slightly longer term capital expenditures are for oil and gas development which has been deferred due to the low commodity price environment.

### Company Gross Reserves First Attributed by Year<sup>(1)</sup>

Proved Undeveloped Reserves																	
	Light Crude Oil and Medium Crude Oil		Heavy Crude Oil		Bitumen		Natural Gas Liquids		Conventional Natural Gas		Shale Gas <sup>(2)</sup>		Coal Bed Methane		Total Oil Equivalent		
	(Mbbbl)		(Mbbbl)		(Mbbbl)		(Mbbbl)		(MMcft)		(MMcft)		(MMcft)		(Mboe) <sup>(3)</sup>		
	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	
2014	1,059	13,137	332	5,483	22,596	77,113	137	832	21,818	66,686	-	-	-	22,728	27,760	111,467	
2015	571	6,418	-	1,512	-	82,204	448	1,277	4,730	21,512	20,825	86,662	-	6,336	5,278	110,495	
2016	345	5,232	-	-	45,978	130,007	2920	4,760	23,826	43,240	-	86,677	-	5,093	53,214	162,500	

Probable Undeveloped Reserves																	
	Light Crude Oil and Medium Crude Oil		Heavy Crude Oil		Bitumen		Natural Gas Liquids		Conventional Natural Gas		Shale Gas <sup>(2)</sup>		Coal Bed Methane		Total Oil Equivalent		
	(Mbbbl)		(Mbbbl)		(Mbbbl)		(Mbbbl)		(MMcft)		(MMcft)		(MMcft)		(Mboe) <sup>(3)</sup>		
	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	
2014	1,446	10,698	356	8,092	78,743	134,485	1,122	2,896	33,494	179,851	-	-	-	6,639	87,246	187,253	
2015	776	6,333	-	5,374	19,185	155,201	492	2,304	6,534	34,975	361,210	561,604	-	5,544	81,744	269,565	
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	

#### Notes:

- (1) "First Attributed" refers to reserves first attributed at year end of the corresponding fiscal year.
- (2) Because of new product type guidelines and designation, Proved and Probable Undeveloped Reserves of shale gas were reported as conventional natural gas prior to 2015.
- (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.

### Proved Undeveloped Reserves

Proved Undeveloped Reserves comprise approximately 57 percent of Company Interest Proved Reserves on a BOE basis. Company Interest Proved Undeveloped Reserves of 163 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 80 percent 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. The Groundbirch Montney gas property amounts to approximately nine percent of our Proved Undeveloped Reserves. Drilling is forecast by GLJ to occur over the next four years to develop these reserves. The Olds/ Garrington area contains approximately nine percent of our Proved Undeveloped Reserves. Development drilling in these fields is primarily focused on the Cardium, Elkton and Ellerslie formations and is forecast to occur over the next four years.

### 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. Our Probable Undeveloped Reserves amount to 284 MMboe and represent about 47 percent 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 (59 percent), Groundbirch (34 percent) and Olds/ Garrington (five percent).

## **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 ten percent per annum) of our total asset retirement obligations, which are inclusive of those costs estimated by GLJ, to be approximately \$113 million as at December 31, 2016, based on a total future liability (inflated at 1.5 percent per annum) of approximately \$2,120 million. The majority of these costs are expected to be incurred after 2056 and apply to 5,459 net producing, non-producing, service and abandoned wells.

The following table summarizes our total current asset retirement obligations as at December 31, 2016:

#### **Asset Retirement Obligations**

	2017	2018	2019	Remainder	Total
Total Abandonment, Reclamation, Remediation & Dismantling (\$millions)	7	26	34	2,053	2,120
Discounted at ten percent (\$millions)	7	21	25	60	113

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 \$514 million (\$197 million when discounted at ten percent) 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 ten percent per annum for the years indicated. All of such development costs are estimated to be incurred in Canada.

### Future Development Costs (\$millions)

Reserve Category	2017	2018	2019	2020	2021	Remainder	Total	
							Undiscounted	Discounted at 10%
Proved Reserves (Constant Prices and Costs)	83	199	157	97	28	899	1,464	678
Proved Reserves (Forecast Prices and Costs)	86	235	201	128	36	1,295	1,980	840
Proved & Probable Reserves (Forecast Prices and Costs)	106	469	746	237	225	3,450	5,234	2,361

We expect to fund future development costs with a combination of cash flow and proceeds from non-core asset dispositions. There are no reserves that are expected to be limited in their recovery due to their cost of development.

## FINDING, DEVELOPMENT AND ACQUISITION COSTS

### Finding and Development Costs

During 2016, we spent \$64.2 million on development, maintenance and optimization, which added 54.0 MMboe of Proved Reserves and 71.4 MMboe of Total Proved Plus Probable Reserves excluding revisions. Incorporating the net positive revisions resulted in an overall change of 60.7 MMboe of Proved Reserves and 76.2 MMboe of Total Proved Plus Probable Reserves. The development and optimization expenditures exclude \$0.6 million in corporate expenditures for information technology projects and equipment inventory. The largest reserve additions were for drilling extensions and infill drilling at Lindbergh and Greater Olds/Garrington.

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 2016, \$60.2 million of asset dispositions (after interim period adjustments) were completed, and approximately \$1.3 million of asset acquisitions were completed. The 2016 dispositions were comprised primarily of non-core assets at Tangleflags, Sukunka, Pine Creek and Sawn Lake.

### 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	2016	2015	2014	2014-2016 Total/Weighted Average
<b>Costs Excluding Future Development Costs</b>				
Exploration and Development Capital Expenditures - \$MM	64.2	181.8	902.5	1,148.5
Exploration and Development Reserve Additions including Revisions - MMboe	60.7	(6.1)	32.9	87.5
<b>Finding and Development Cost - \$/BOE<sup>(1)</sup></b>	<b>1.06</b>	<b>(29.80)</b>	<b>27.43</b>	<b>13.13</b>
<hr/>				
Net Acquisition (Disposition) Capital - \$MM	(58.9)	(209.6)	(67.5)	(336.0)
Net Acquisition (Disposition) Reserve Additions - MMboe	(6.1)	(25.8)	(3.1)	(35.0)
<b>Net Acquisition Cost - \$/BOE</b>	<b>9.66</b>	<b>8.12</b>	<b>21.77</b>	<b>9.60</b>
<hr/>				
Total Capital Expenditures including Net Acquisitions (Dispositions) - \$MM	5.3	(27.8)	835.0	812.5
Reserve Additions including Net Acquisitions (Dispositions) - MMboe	54.6	(31.9)	29.8	52.5
<b>Finding, Development and Acquisition Cost - \$/BOE<sup>(2)</sup></b>	<b>0.10</b>	<b>0.87</b>	<b>28.02</b>	<b>15.48</b>
<hr/>				
<b>Costs Including Future Development Costs</b>				
Exploration and Development Capital Expenditures - \$MM	64.2	181.8	902.5	1,148.5
Exploration and Development Change in FDC - \$MM	423.6	(239.7)	(51.7)	132.2
Exploration and Development Capital including Change in FDC - \$MM	487.8	(57.9)	850.8	1,280.7
Exploration and Development Reserve Additions including Revisions - MMboe	60.7	(6.1)	32.9	87.5
<b>Finding and Development Cost - \$/BOE</b>	<b>8.04</b>	<b>9.49</b>	<b>25.86</b>	<b>14.64</b>
<hr/>				
Net Acquisition (Disposition) Capital - \$MM	(58.9)	(209.6)	(67.5)	(336.0)
Net Acquisition (Disposition) FDC - \$MM	(40.6)	(107.3)	(5.3)	(153.2)
Net Acquisition (Disposition) Capital including FDC - \$MM	(99.5)	(316.9)	(72.8)	(489.2)
Net Acquisition (Disposition) Reserve Additions - MMboe	(6.1)	(25.8)	(3.1)	(35.0)
<b>Net Acquisition Cost - \$/BOE</b>	<b>16.31</b>	<b>12.28</b>	<b>23.48</b>	<b>13.98</b>
<hr/>				
Total Capital Expenditures including Net Acquisitions (Dispositions) - \$MM	5.3	(27.8)	835.0	812.5
Total Change in FDC - \$MM	383.0	(347.0)	(57.0)	(21.0)
Total Capital including Change in FDC - \$MM	388.3	(374.8)	778.0	791.5
Reserve Additions including Net Acquisitions (Dispositions) - MMboe	54.6	(31.9)	29.8	52.5
<b>Finding, Development and Acquisition Cost including FDC - \$/BOE</b>	<b>7.11</b>	<b>11.75</b>	<b>26.11</b>	<b>15.08</b>

<b>Total Proved Plus Probable Reserves</b>	<b>2016</b>	<b>2015</b>	<b>2014</b>	<b>2014-2016 Total/Weighted Average</b>
<b>Costs Excluding Future Development Costs</b>				
Exploration and Development Capital Expenditures - \$MM	64.2	181.8	902.5	1,148.5
Exploration and Development Reserve Additions including Revisions - MMboe	76.2	73.6	112.4	262.2
<b>Finding and Development Cost - \$/BOE</b>	<b>0.84</b>	<b>2.47</b>	<b>8.03</b>	<b>4.38</b>
<b>Costs Including Future Development Costs</b>				
Exploration and Development Capital Expenditures - \$MM	64.2	181.8	902.5	1,148.5
Exploration and Development Change in FDC - \$MM	193.7	341.9	1,607.2	2,142.8
Exploration and Development Capital including Change in FDC - \$MM	257.9	523.7	2,509.7	3,291.3
Exploration and Development Reserve Additions including Revisions - MMboe	76.2	73.6	112.4	262.2
<b>Finding and Development Cost - \$/BOE</b>	<b>3.38</b>	<b>7.12</b>	<b>22.33</b>	<b>12.55</b>
Net Acquisition (Disposition) Capital - \$MM	(58.9)	(209.6)	(67.5)	(336.0)
Net Acquisition (Disposition) FDC - \$MM	(124.7)	(133.9)	(32.2)	(290.8)
Net Acquisition (Disposition) Capital including FDC - \$MM	(183.6)	(343.5)	(99.7)	(626.8)
Net Acquisition (Disposition) Reserve Additions - MMboe	(15.9)	(35.8)	(5.6)	(57.3)
<b>Net Acquisition Cost - \$/BOE</b>	<b>11.55</b>	<b>9.59</b>	<b>17.80</b>	<b>10.94</b>
Total Capital Expenditures including Net Acquisitions (Dispositions) - \$MM	5.3	(27.8)	835.0	812.5
Total Change in FDC - \$MM	69.0	208.0	1,575.0	1,852.0
Total Capital including Change in FDC - \$MM	74.3	180.2	2,410.0	2,664.5
Reserve Additions including Net Acquisitions (Dispositions) - MMboe	60.3	37.8	106.7	204.9
<b>Finding Development and Acquisition Cost including FDC - \$/BOE</b>	<b>1.23</b>	<b>4.77</b>	<b>22.57</b>	<b>13.00</b>

**Notes:**

- (1) The negative 2015 F&D Cost excluding FDC for Proved Reserves is due to the negative reserve change including revisions.
- (2) The negative FD&A Costs excluding FDC for 2015 P+P Reserves are due to the proceeds from dispositions exceeding capital expenditures plus acquisition costs.

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 P+P 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.

	<b>2016</b>	<b>2015</b>	<b>2014</b>	<b>2014-2016 Weighted Average</b>
Recycle Ratio	8.5	3.5	1.1	2.1
Operating Netback, \$/BOE <sup>(1)(3)</sup>	28.87	24.97	25.64	26.32
P+P F&D, \$/BOE <sup>(2)</sup>	3.38	7.12	22.33	12.55

**Notes:**

- (1) Operating netback is calculated as shown in "Production History (Netback)".
- (2) P+P F&D uses Exploration and Development capital including change in FDC divided by Exploration and Development Reserve Additions including Revisions as shown above.
- (3) Comparative figures restated to conform to presentation in the current period.

## RESERVE LIFE INDEX

The Reserve Life Index ("RLI") provides a comparative measure of the longevity of the resources. We calculate the RLI by dividing 2016 Company Interest year end reserves by GLJ's 2017 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	6.4	15.4	31.8
Reserves, Mboe <sup>(1)(2)</sup>	115,493	285,806	608,549
2017 Forecast Production, BOE/d <sup>(1)</sup>	49,361	50,998	52,429

### 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.

	2016	2015	2014	Weighted Average/Total 2014-2016
Without Net Acquisitions Proved Plus Probable Replacement (%)	365	282	420	355
P+P Additions plus Revisions, MMboe <sup>(1)</sup>	76.2	73.6	112.4	262.2
With Net Acquisitions Proved Plus Probable Replacement (%)	289	145	399	278
P+P Additions, Revisions plus net Acquisitions, MMboe <sup>(1)</sup>	60.3	37.8	106.7	204.8
Without Net Acquisitions Total Proved Replacement (%)	290	(23)	123	119
Total Proved Additions plus Revisions, MMboe <sup>(1)</sup>	60.7	(6.1)	32.9	87.5
With Net Acquisitions Total Proved Replacement (%)	261	(122)	111	71
Total Proved Additions, Revisions plus net Acquisitions, MMboe <sup>(1)</sup>	54.6	(31.9)	29.8	52.5
Current Year Production, MMboe <sup>(1)</sup>	20.9	26.1	26.8	73.8

### Note:

- (1) Both reserves and production are Company Interest.

## OTHER OIL AND GAS INFORMATION

### Oil and Gas Wells

As at December 31, 2016, we had an interest in 4,406 gross (2,464 net) producing oil and natural gas wells and 2,464 gross (1,375 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
<b>Crude Oil Wells</b>						
Alberta	1,707	917	983	467	2,690	1,384
British Columbia	75	43	197	130	272	173
Saskatchewan	60	2	15	5	75	7
<b>Bitumen Wells</b>						
Alberta	22	22	-	-	22	22
<b>Natural Gas Wells</b>						
Alberta	2,393	1,399	703	423	3,096	1,822
British Columbia	137	79	187	107	324	186
Saskatchewan	1	1	9	3	10	4
Nova Scotia	11	1	10	1	21	2
<b>Other</b>						
Alberta	-	-	271	178	271	178
British Columbia	-	-	87	59	87	59
Saskatchewan	-	-	2	2	2	2
<b>Total</b>	<b>4,406</b>	<b>2,464</b>	<b>2,464</b>	<b>1,375</b>	<b>6,870</b>	<b>3,839</b>

### 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, 2016 and the maximum net area of unproved properties for which we expect our rights to explore, develop and exploit to expire during 2017. 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, 2016

Location	Gross Acres	Net Acres	Maximum Net Acres Expected to Expire During 2017
Alberta	519,634	265,617	43,174
British Columbia	273,885	132,054	25,159
Nova Scotia	200,650	15,957	-
Saskatchewan	4,404	1,932	-
<b>Total</b>	<b>998,573</b>	<b>415,559</b>	<b>68,332</b>

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.

## 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 17 of our annual audited consolidated financial statements and related Management's Discussion and Analysis for the year ended December 31, 2016, which may be found on our website at [www.pengrowth.com](http://www.pengrowth.com), on SEDAR at [www.sedar.com](http://www.sedar.com) and on EDGAR at [www.sec.gov](http://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 2023, partially as a result of our \$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, 2016. These costs include only those costs which are cash or cash equivalent.

Nature of Cost	Amount (\$million)
Acquisition Costs	
Proved	1.3
Unproved	-
Exploration Costs	0.3
Development Costs	63.4
<b>Total</b>	<b>65.0</b>

## EXPLORATION AND DEVELOPMENT ACTIVITIES

The following table summarizes the number of wells drilled during the financial year ended December 31, 2016.

Wells	Development		Exploration		Total	
	Gross	Net	Gross	Net	Gross	Net
Gas	1	0.2	-	-	1	0.2
Oil	-	-	-	-	-	-
Bitumen	-	-	-	-	-	-
Service	-	-	-	-	-	-
Stratigraphic Test	-	-	-	-	-	-
Dry	-	-	-	-	-	-
<b>Total</b>	<b>1</b>	<b>0.2</b>	<b>0</b>	<b>0</b>	<b>1</b>	<b>0.2</b>

## PRODUCTION ESTIMATES

The following table summarizes the 2017 average daily volume of gross production estimated by GLJ for all properties held on December 31, 2016 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 2017 Company Interest production to be between 50,000 and 52,000 BOE/d.

	2017 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)	11,280	274	11,554	11,309	287	11,596
Heavy Crude Oil (bbl/d)	2	-	2	2	-	2
Bitumen (bbl/d)	14,378	295	14,673	14,378	295	14,673
Conventional Natural Gas (Mcf/d)	94,634	3,525	98,159	95,145	3,161	98,306
Shale Gas (Mcf/d)	9,733	410	10,143	9,733	410	10,143
Coal Bed Methane (Mcf/d)	5,101	72	5,173	5,101	72	5,173
Natural Gas Liquids (bbl/d)	6,776	288	7,064	6,839	237	7,076
<b>Total (BOE/d)</b>	<b>50,680</b>	<b>1,525</b>	<b>52,205</b>	<b>50,858</b>	<b>1,426</b>	<b>52,284</b>

## 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				YEAR ENDED
	Mar 31, 2016	June 30, 2016	Sept 30, 2016	Dec 31, 2016	Dec 31, 2016
<b>Barrels of Oil Equivalent<sup>(1)</sup> (including realized commodity risk management)</b>					
Average Daily Oil Production <sup>(2)</sup> (BOE/d)	62,056	56,735	55,137	54,354	57,058
Oil & gas sales (\$/BOE) (includes other income)	20.22	26.57	28.70	33.84	27.11
Royalties (\$/BOE)	(1.43)	(1.51)	(1.97)	(2.82)	(1.91)
Operating expenses (\$/BOE)	(12.41)	(12.92)	(13.52)	(14.00)	(13.19)
Transportation costs (\$/BOE)	(1.56)	(1.61)	(1.66)	(1.64)	(1.61)
Realized commodity risk management	22.49	14.93	20.58	15.44	18.47
<b>Operating netback (\$/BOE)</b>	<b>27.31</b>	<b>25.46</b>	<b>32.13</b>	<b>30.82</b>	<b>28.87</b>
<b>Light Crude Oil (excluding realized commodity risk management)</b>					
Average Daily Oil Production <sup>(2)</sup> (bbl/d)	13,396	11,747	11,221	10,597	11,736
Sales (\$/bbl)	38.56	52.85	52.50	59.59	50.24
Royalties (\$/bbl)	(3.59)	(4.37)	(7.40)	(8.26)	(5.76)
Operating expenses (\$/bbl)	(15.49)	(12.82)	(18.83)	(18.98)	(17.01)
Transportation costs (\$/bbl)	(1.13)	(1.42)	(1.68)	(1.43)	(1.40)
<b>Operating netback (\$/bbl)</b>	<b>18.35</b>	<b>34.24</b>	<b>24.59</b>	<b>30.92</b>	<b>26.07</b>
<b>Heavy Crude Oil (excluding realized commodity risk management)</b>					
Average Daily Heavy Oil Production <sup>(2)</sup> (bbl/d)	16,448	15,502	15,190	15,209	15,585
Sales (\$/bbl)	15.63	34.10	34.13	37.88	30.19
Royalties (\$/bbl)	(0.74)	0.03	(0.71)	(0.86)	(0.57)
Operating expenses (\$/bbl)	(10.19)	(7.91)	(9.14)	(9.65)	(8.86)
Transportation costs (\$/bbl)	(2.83)	(2.93)	(2.86)	(2.89)	(2.88)
<b>Operating netback (\$/bbl)</b>	<b>1.87</b>	<b>23.29</b>	<b>21.42</b>	<b>24.48</b>	<b>17.88</b>
<b>Natural Gas (excluding realized commodity risk management)</b>					
Average Daily Natural Gas Production <sup>(2)</sup> (Mcf/d)	144,306	130,248	129,520	123,434	131,847
Sales (\$/Mcf)	2.15	1.51	2.37	3.03	2.25
Royalties (\$/Mcf)	0.08	-	0.15	0.06	0.07
Operating expenses (\$/Mcf)	(1.97)	(2.62)	(2.20)	(2.32)	(2.27)
Transportation costs (\$/Mcf)	(0.24)	(0.23)	(0.22)	(0.24)	(0.23)
<b>Operating netback (\$/Mcf)</b>	<b>0.02</b>	<b>(1.34)</b>	<b>0.10</b>	<b>0.53</b>	<b>(0.18)</b>
<b>NGL (excluding realized commodity risk management)</b>					
Average Daily NGL Production <sup>(2)</sup> (bbl/d)	8,162	7,778	7,139	7,976	7,763
Sales (\$/bbl)	18.85	18.93	21.62	30.80	22.60
Royalties (\$/bbl)	(5.07)	(4.43)	(4.75)	(7.65)	(5.50)
Operating expenses (\$/bbl)	(13.65)	(15.17)	(15.37)	(15.92)	(14.86)
Transportation costs (\$/bbl)	-	-	-	-	-
<b>Operating netback (\$/bbl)</b>	<b>0.13</b>	<b>(0.67)</b>	<b>1.50</b>	<b>7.23</b>	<b>2.24</b>

### 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.

## 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.

### Debentures

As a result of the acquisition of NAL Energy Corporation on May 31, 2012, we assumed all of NAL Energy Corporation's covenants and obligations with respect to the 6.25% Series B Convertible Debentures. A copy of the relevant indenture can be found under our profile on [www.sedar.com](http://www.sedar.com).

Our 6.25% Series B Convertible Debentures have a face value of \$1,000, bear interest at the rate of 6.25 percent per annum payable semi-annually in arrears on the last day of March and September of each year and mature on March 31, 2017. The 6.25% Series B Convertible Debentures are convertible at the holder's option at a conversion price of \$11.5116 per Common Share, subject to adjustment in certain events.

On February 25, 2016, we announced the launch of a normal course issuer bid for up to 10 percent of our 6.25% Series B Convertible Debentures. Through to expiry of the normal course issuer bid on February 28, 2017, 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.

### Stock Exchange Listings

Our Common Shares are listed and posted for trading on the TSX under the symbol "PGF" and on the NYSE under the symbol "PGH". Our 6.25% Series B Convertible Debentures are listed and posted for trading on the TSX under the symbol "PGF.DB.B".

## **DIVIDENDS**

Effective January 20, 2016, we suspended paying a dividend. Prior to suspending our dividend, a decision which is reviewed quarterly, we paid a quarterly dividend to our Shareholders on the 15<sup>th</sup> day (or the first business day following the 15<sup>th</sup>) of each of March, June, September and December. The record date for any dividend prior to suspension was the last business day of the month preceding the dividend date or such other date as may be determined by our Board.

### Historical Dividends

Dividends can and may fluctuate in the future. Actual future cash dividends, if any, will be subject to the discretion of our Board of Directors and may vary depending on a variety of factors and conditions existing from time to time, including fluctuations in commodity prices, production levels, capital expenditure requirements, debt service requirements, operating costs, royalty burdens, foreign exchange rates and the satisfaction of the liquidity and solvency tests imposed by the ABCA for the declaration and payment of dividends. We cannot provide assurance that cash flow will be available for distribution to Shareholders in the amounts anticipated or at all. See "Risk Factors".

The following table sets forth dividends declared by the Corporation in 2016, 2015 and 2014 on the outstanding Common Shares for the periods indicated, with each amount being paid in the following month. Prior to October 2015, dividends were paid monthly.

Month Declared	2016 (\$/share)	2015 (\$/share)	2014 (\$/share)
January	-	0.04	0.04
February	-	0.02	0.04
March	-	0.02	0.04
April	-	0.02	0.04
May	-	0.02	0.04
June	-	0.02	0.04
July	-	0.02	0.04
August	-	0.02	0.04
September	-	-	0.04
October	-	-	0.04
November	-	0.01	0.04
December	-	-	0.04
<b>Total</b>	-	<b>0.19</b>	<b>0.48</b>

All of these dividends are "eligible dividends" for the purposes of the Tax Act.

### Restrictions on Dividends

Our ability to pay cash dividends to Shareholders may be directly or indirectly affected in certain events as a result of certain restrictions, including restrictions set forth in: (i) the credit agreement relating to our Credit Facility; (ii) the note purchase agreements relating to the 2007 Senior Notes, the 2008 Senior Notes, the 2010 Senior Notes and the 2012 Senior Notes; and (iii) the solvency tests in the ABCA. In particular, the funds required to satisfy the interest payable on the foregoing obligations, as well as the amounts payable upon the redemption or maturity of such obligations, as applicable, or upon a Default or an Event of Default (both as defined below), will be deducted and withheld from the amounts that would otherwise be payable as dividends to Shareholders.

### ABCA Solvency Tests

The payment of dividends by a corporation is governed by the liquidity and insolvency tests described in the ABCA. Pursuant to the ABCA, after the payment of a dividend, we must be able to pay our liabilities as they become due, and the realizable value of our assets must be greater than our liabilities and the legal stated capital of our outstanding securities. As at December 31, 2016, our legal stated capital was approximately \$1.6 billion.

### Revolving Credit Facility

The credit agreement relating to the Credit Facility stipulates that we shall not make or agree to make cash dividends or other distributions to Shareholders when a "Default" (subject to certain exceptions) or an "Event of Default" has occurred or is continuing or would reasonably be expected to occur as a result of such dividend or distribution. "Events of Default" are defined in the credit agreement to include those events of default typically referred to in a loan agreement of such type and include, among other things; (i) the failure to repay amounts owing under the Credit Facility; (ii) our voluntary or involuntary insolvency; (iii) the default of obligations owing under other debt arrangements; and (iv) a change in control of us. "Default" is defined in the credit agreement to mean any event or circumstance which, with the giving of notice or lapse of time or otherwise, would constitute an Event of Default.

On March 30, 2015 we renewed and extended our Credit Facility from July 26, 2017 to March 31, 2019. At this time we also amended the maximum permitted Senior Debt to EBITDA ratio from 3.0 to 3.5 and the Total Debt to EBITDA ratio from 3.5 to 4.0. Previously, these covenants were scheduled to revert back to their prior permitted levels of 3.0 and 3.5, respectively, after December 31, 2015. All other material terms and conditions remained unchanged.

On December 10, 2015, we amended our Credit Facility by increasing the maximum permitted Senior Debt to Total Capitalization ratio from 50 percent to 55 percent. This amendment was obtained to align this covenant between our Credit Agreement and various note purchase agreements which already allowed a maximum Senior Debt to Total Capitalization ratio of 55 percent. All other material terms and conditions remained unchanged.

On February 9, 2017, Pengrowth amended its Credit Facility to remove the covenant respecting Senior Debt to Total Capitalization (as both defined below).

In addition to the standard representations, warranties and covenants commonly contained in a credit facility of this nature, the Credit Facility includes the following key financial covenants as at February 28, 2017:

- The ratio of Senior Debt (as defined below) to EBITDA (as defined below) at the end of any fiscal quarter shall not exceed 3.5:1; and

- The ratio of Total Debt (as defined below) to EBITDA (as defined below) at the end of any fiscal quarter shall not exceed 4.0:1.

With respect to the financial covenants, the following definitions apply to the Corporation:

Senior Debt: All obligations, liabilities and indebtedness classified as debt on the balance sheet of the Corporation.

Total Debt: The aggregate of Senior Debt and Subordinated Debt.

EBITDA: The aggregate of the last four fiscal quarters' net income from operations plus the sum of:

- Income taxes;
- Interest expense;
- All provisions for federal, provincial or other income and capital taxes;
- Depreciation, depletion and amortization expense; and
- Other non-cash items.

Material Acquisition: An acquisition or series of acquisitions which increases the tangible assets of Pengrowth by more than five percent.

Subordinated Debt: Debt which, by its terms, is subordinated to the lenders under the Credit Facility.

### Senior Unsecured Notes

The terms of the note agreements ensure note holders have priority over our Shareholders with respect to our assets and income.

The holders of the 2007 Senior Notes, 2008 Senior Notes, 2010 Senior Notes and 2012 Senior Notes are entitled to certain remedies upon the occurrence of an "Event of Default", which remedies may restrict our ability to pay dividends to Shareholders. An "Event of Default" is defined in the note purchase agreements to include those events of default which are typically referred to in a note purchase agreement of a similar nature (including failure to pay principal and interest when due, default in compliance with other covenants, inaccuracy of representations and warranties, cross default to other indebtedness, certain events of insolvency or the rendering of judgments against the Corporation in excess of certain threshold amounts). "Default" is defined in the note agreements to mean any event or circumstance which, after the giving of notice or lapse of time or both, would constitute an Event of Default.

In addition to standard representations, warranties and covenants the note agreements contain the following key financial covenants:

- The ratio of EBITDA (as defined below) to interest expense for the four immediately preceding fiscal quarters shall not be less than 4:1;
- Total Debt (as defined below) to Total Capitalization (as defined below) shall not exceed 55 percent at the end of each fiscal quarter; and
- The ratio of Total Debt to EBITDA for each period of four consecutive fiscal quarters shall not exceed 3.5:1

On December 21, 2016, Pengrowth received a temporary waiver under our Term Note agreements that allows the Total Debt to Total Capitalization to exceed 55 percent for the period ending December 31, 2016.

With respect to these financial covenants, the following definitions apply to the Corporation:

EBITDA: The sum of the last four fiscal quarters of (i) net income determined in accordance with GAAP; (ii) all provisions for federal, provincial or other income and capital taxes; (iii) all provisions for depletion, depreciation, and amortization, (iv) interest expense; and (v) non-cash items.

Total Debt: Has substantially the same meaning as "Senior Debt" in the definitions relating to the Credit Facility.

Total Capitalization: Total Debt plus shareholder equity in the Corporation.

## INDUSTRY CONDITIONS

Companies operating in the oil and natural gas industry are subject to extensive regulation and control of operations (including land tenure, exploration, development, production, refining and upgrading, transportation, and marketing) as a result of legislation enacted by various levels of government with respect to the pricing and taxation of oil and natural gas, including the governments of Canada, Alberta, British Columbia, Saskatchewan and Nova Scotia, all of which investors in the oil and gas industry should carefully consider. All current legislation is a matter of public record and we are unable to predict what additional legislation or amendments governments may enact in the future. The following comprises some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry.

## Pricing and Marketing

### **Oil**

In Canada, producers of oil are entitled to negotiate sales contracts directly with oil purchasers, which results in the market determining the price of oil. Worldwide supply and demand factors primarily determine oil prices; however, regional market and transportation issues also influence prices. The specific price depends in part on oil quality, prices of competing fuels, distance to market, availability of transportation, value of refined products, the supply/demand balance and contractual terms of sale. Oil exporters are also entitled to enter into export contracts with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude oil, provided that an order approving such export has been obtained from the National Energy Board of Canada (the "NEB"). Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export licence from the NEB. The NEB underwent a consultation process to update the regulations governing the issuance of export licences. The updating process was necessary to meet the criteria set out in the federal *Jobs, Growth and Long-term Prosperity Act (Canada)* (the "**Prosperity Act**") which received Royal Assent on June 29, 2012. The *Regulations Amending the National Energy Board Act Part VI (Oil and Gas) Regulations* came into effect on July 31, 2015 and provides the requirements for obtaining long-term licences.

### **Natural Gas**

Canada's natural gas market has been deregulated since 1985. Supply and demand determine the price of natural gas and price is calculated at the sale point, being the wellhead, the outlet of a gas processing plant, on a gas transmission system, at a storage facility, at the inlet to a utility system or at the point of receipt by the consumer. Accordingly, the price for natural gas is dependent upon such producer's own arrangements (whether long or short term contracts and the specific point of sale). As natural gas is also traded on trading platforms such as the Natural Gas Exchange, Intercontinental Exchange or the New York Mercantile Exchange in the United States, spot and future prices can also be influenced by supply and demand fundamentals on these platforms. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. 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 Government of Canada. Natural gas (other than propane, butane and ethane) exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 m<sup>3</sup> per day) must be made pursuant to an NEB order. Natural gas export contracts of a longer duration (to a maximum of 40 years) or that deal with larger quantities of natural gas requires an exporter to obtain an export licence from the NEB.

### **Natural Gas Liquids**

The price of NGL sold in intraprovincial, interprovincial and international trade is determined by negotiation between buyers and sellers. Such price depends, in part, on the quality of the NGL, prices of competing chemical feed stock, distance to market, access to downstream transportation, length of contract term, the supply/demand balance and other contractual terms. NGL exported from Canada are subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain criteria prescribed by the NEB and the Government of Canada. NGL may be exported for a term of no more than one year in respect to propane and butane, and no more than two years in respect to ethane, all exports requiring an order of the NEB.

## The North American Free Trade Agreement

The North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, the United States and Mexico came into force on January 1, 1994. In the context of energy resources, Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to the total supply of goods of the party maintaining the restriction as compared to the proportion prevailing in the most recent 36 month period; (ii) impose an export price higher than the domestic price (subject to an exception with respect to certain measures which only restrict the volume of exports); and (iii) disrupt normal channels of supply.

All three signatory countries are prohibited from imposing a minimum or maximum export price requirement in any circumstance where any other form of quantitative restriction is prohibited. The signatory countries are also prohibited from imposing a minimum or maximum import price requirement except as permitted in enforcement of countervailing and anti-dumping orders and undertakings. NAFTA requires energy regulators to ensure the orderly and equitable implementation of any regulatory changes and to ensure that the application of those changes will cause minimal disruption to contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements, all of which are important for Canadian oil and natural gas exports. NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector and prohibits discriminatory border restrictions and export taxes. The new administration in the United States has indicated an intention to seek renegotiation of NAFTA, the impact of which on the oil and gas industry is uncertain.

## Royalties and Incentives

### **General**

In addition to federal regulation, 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, crude oil, natural gas liquids, sulphur and natural gas 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 product produced. Other royalties and royalty-like interests are carved out of the working interest owner's interest, from time to time, through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests or net carried interests.

Occasionally the governments of the western Canadian provinces create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays or royalty tax credits and are generally introduced when commodity prices are low to encourage exploration and development activity by improving earnings and cash flow within the industry.

The Canadian Federal Government has signaled that it will, *inter alia*, phase out subsidies for the oil and gas industry, which include only allowing the use of the Canadian Exploration Expenses tax deduction in cases of successful exploration, implementing stringent reviews for pipelines and establishing a pan-Canadian framework for combating climate change. These changes could affect earnings of companies operating in the oil and natural gas industry.

### **Alberta**

In Alberta, the Crown owns 81 percent of the province's mineral rights. The remaining 19 percent are 'freehold' mineral rights owned by the Federal Government on behalf of First Nations or in National Parks, and by individuals and companies. Provincial Government royalty rates apply to Crown-owned mineral rights. On January 29, 2016, the Government of Alberta released and accepted the Royalty Review Advisory Panel's recommendations, which outlined the implementation of a "Modernized Royalty Framework" for Alberta (the "**MRF**"). The MRF formally took effect on January 1, 2017, for wells drilled after that date. Wells drilled prior to January 1, 2017, will continue to be governed by the "**New Royalty Framework**" (implemented by the *Mines and Minerals (New Royalty Framework) Amendment Act, 2008*) (the "**Alberta Royalty Framework**") for a period of ten years until January 1, 2027. The MRF is structured in three phases: (i) Pre-Payout; (ii) Mid-Life; and (iii) Mature. During the Pre-Payout phase, a fixed five percent royalty will apply until the well reaches payout. Well payout occurs when the cumulative revenue from a well is equal to the Drilling and Completion Cost Allowance (determined by a formula that approximates drilling and completion costs for wells based on total depth, length, and proppant placed). The new royalty rate for Pre-Payout under the MRF will be payable on gross revenue generated from all production streams (oil, gas, and natural gas liquids), eliminating the need to label a well as "oil" or "gas". Post-payout, the Mid-Life phase will apply a higher royalty rate than the Pre-Payout phase. Depending on the commodity price of the substance the well is producing, the royalty rate could range from 5% - 40%. The metrics for calculating the Mid-Life phase royalty are based on commodity prices and are intended, on average, to yield the same internal rate of return as under the Alberta Royalty Framework. In the Mature phase of the MRF, once a well reaches the tail end of its cycle and production falls below a "Maturity Threshold", currently the equivalent of 194 m<sup>3</sup> (40 barrels of oil equivalent per day or 345,500m<sup>3</sup> of gas per month), the royalty rate will move to a sliding scale (based on volume and price) with a minimum royalty rate of five percent. The downward adjustment of the royalty rate in the Mature phase is intended to account for the higher per-unit fixed cost involved in operating an older well.

On July 11, 2016, the Government of Alberta released details of the Enhanced Hydrocarbon Recovery Program and the Emerging Resources Program. These programs, that came into effect on January 1, 2017, are a part of the MRF and account for the higher costs associated with enhanced recovery methods and with developing emerging resources in an effort to make difficult investments economically viable and to increase royalties. Certain eligibility criteria must be satisfied in order for a proposed project to fall under each program. Enhanced recovery scheme applications can be submitted to the AER.

Oil sands projects are also subject to Alberta's royalty regime. The MRF does not change the oil sands royalty framework, however, the Government of Alberta plans to increase transparency in the method and figures by which the royalties are calculated. 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 one percent and nine percent depending on the market price of oil, determined using the average monthly price, expressed in Canadian dollars, for WTI crude oil at Cushing, Oklahoma. Rates are one percent when the market price of oil is less than or equal to \$55 per barrel and increase for every dollar of market price of oil increase to a maximum of nine percent when 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 one percent and nine percent and the net revenue royalty based on the net revenue royalty rate. Net revenue royalty rates start at 25 percent and increase for every dollar of market price of oil increase above \$55 up to 40 percent when oil is priced at \$120 or higher.

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

Royalties, for wells drilled prior to January 1, 2017 are paid pursuant to the Alberta Royalty Framework until January 1, 2027. Royalty rates for conventional oil are set by a single sliding scale formula, which is applied monthly and incorporates separate variables to account for

production rates and market prices. The maximum royalty payable under the royalty regime is 40 percent. Royalty rates for natural gas under the royalty regime depends on the price of each of the components of the gas stream, the productivity of the well, its acid gas factor and the depth of the producing zone. These factors are employed on a sliding scale formula to determine the natural gas royalty rate per well with the maximum royalty payable under the royalty regime set at 36 percent and a minimum royalty rate of five percent.

Producers of oil and natural gas from freehold lands in Alberta are required to pay freehold mineral tax. The freehold mineral tax is a tax levied by the Government of Alberta on the value of oil and natural gas production from lands where the Crown does not hold the rights to mines and minerals and is derived from the *Freehold Mineral Rights Tax Act* (Alberta). The freehold mineral tax is levied on an annual basis on calendar year production 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. The basic formula for the assessment of freehold mineral tax is: revenue less allocable costs equals net revenue divided by wellhead production equals the value based upon unit of production. If payors do not wish to file individual unit values, a default price is supplied by the Crown. On average, the tax levied is four percent of revenues reported from freehold mineral title properties.

The Government of Alberta has from time to time implemented drilling credits, incentives or transitional royalty programs to encourage oil and gas development and new drilling. For example, the Innovative Energy Technologies Program (the "IETP") has the stated objectives of increasing recovery from oil and gas deposits, finding technical solutions to the gas over bitumen issue, improving the recovery of bitumen by in-situ and mining techniques and improving the recovery of natural gas from coal seams. The IETP provides royalty adjustments to specific pilot and demonstration projects that utilize new or innovative technologies to increase recovery from existing reserves.

In addition, the Government of Alberta has implemented certain initiatives intended to accelerate technological development and facilitate the development of unconventional resources (the "**Emerging Resource and Technologies Initiative**"). These initiatives apply to wells drilled before January 1, 2017, for a ten-year period, until January 1, 2027. Specifically:

- Coalbed methane wells will receive a maximum royalty rate of five percent for 36 producing months up to 750 MMcf of production, retroactive to wells that began producing on or after May 1, 2010;
- Shale gas wells will receive a maximum royalty rate of five percent for 36 producing months with no limitation on production volume, retroactive to wells that began producing on or after May 1, 2010;
- Horizontal gas wells will receive a maximum royalty rate of five percent for 18 producing months up to 500 MMcf of production, retroactive to wells that commenced drilling on or after May 1, 2010; and
- Horizontal oil wells and horizontal non-project oil sands wells will receive a maximum royalty rate of five percent with volume and production month limits set according to the depth of the well (including the horizontal distance), retroactive to wells that commenced drilling on or after May 1, 2010.

### **British Columbia**

Producers of oil and natural gas from Crown lands in British Columbia are required to pay annual rental payments and make monthly royalty payments in respect of oil and natural gas produced. The amount payable as a royalty in respect of oil depends on the type and vintage of the oil, the quantity of oil produced in a month and the value of that oil. Generally, oil is classified as either light or heavy and the vintage of oil is classified as either "**old oil**", which is produced from a pool discovered before October 31, 1975, "**new oil**" produced from a pool discovered between October 31, 1975 and June 1, 1998, and "**third-tier oil**" produced from a pool discovered after June 1, 1998 or through an enhanced oil recovery ("**EOR**") scheme. The royalty calculation takes into account the production of oil on a well-by-well basis, the specified royalty rate for a given vintage of oil, the average unit selling price of the oil and any applicable royalty exemptions. Royalty rates are reduced on low-productivity wells, reflecting the higher unit costs of extraction, and are the lowest for third tier oil, reflecting the higher unit costs of both exploration and extraction.

The royalty payable in respect of natural gas produced on Crown lands is determined by a sliding scale formula based on a reference price, which is the greater of the average net price obtained by the producer and a prescribed minimum price. For non-conservation gas (not produced in association with oil), the royalty rate depends on the date of acquisition of the oil and natural gas tenure rights and the spud date of the well, and may also be impacted by the select price, a parameter used in the royalty rate formula to account for inflation. Royalty rates are fixed for certain classes of non-conservation gas when the reference price is below the select price. Conservation gas is subject to a lower royalty rate than non-conservation gas. Royalties on natural gas liquids are levied at a flat rate of 20 percent of sales volume.

Producers of oil and natural gas from freehold lands in British Columbia are required to pay monthly freehold production taxes. For oil, the applicable freehold production tax is based on the volume of monthly production and 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 the reference price similar to that applied to natural gas production on Crown land, and depends on whether the natural gas is conservation gas or non-conservation gas. The production tax rate for freehold natural gas liquids is a flat rate of 12.25 percent.

As of January 1, 2017, all liquid natural gas ("**LNG**") facilities are subject to a 3.5 percent income tax. This income tax is scheduled to increase to five percent in 2037. During the period in which net operating losses and capital investment are deducted, a tax rate of 1.5 percent will apply to the taxpayer's net income. Once the net operating losses and capital investment have been depleted, the full rate of 3.5 percent

is payable. To encourage investment, the Government of British Columbia will offer a corporate income tax credit to any LNG taxpayer based on the amount of LNG acquired for an LNG facility.

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, including the following:

- *Deep Well Royalty Credit Program* providing a royalty credit for natural gas wells defined in terms of a dollar amount applied against royalties, is well specific and applies to drilling and completion costs for vertical wells with a true vertical depth greater than 2,500 metres and horizontal wells with a true vertical depth greater than 1,900 metres (or 2,300 metres if spud before September 1, 2009) and if certain other criteria are met, is intended to reflect the higher drilling and completion costs. Effective April 1, 2014, there are two tiers to the Deep Well Royalty Credit Program, "tier one" and "tier two". The pre-existing Deep Well Royalty Credit Program, as described above, will comprise tier two of the program. Tier one of the Deep Well Royalty Credit Program applies to shallower horizontal wells with a true vertical depth less than or equal to 1,900 metres if spud after March 31, 2014. Currently all wells that qualify for the tier one royalty credits are subject to a minimum royalty of six percent while wells that qualify for the tier two royalty credits are subject to a minimum royalty of three percent. These minimum royalty amounts apply when the net royalty payable would otherwise be zero for a production month;
- *Deep Re-Entry Royalty Credit Program* providing a royalty credit for deep re-entry wells with a true vertical depth to the top of pay if the re-entry well event is greater than 2,300 metres and a re-entry date after November 30, 2003; or if the well was spud on or after January 1, 2009, with a true vertical depth to the completion point of the re-entry well event being greater than 2,300 metres;
- *Deep Discovery Royalty Credit Program* providing the lesser of a 3-year royalty holiday or 283,000,000 m<sup>3</sup> of royalty free gas for deep discovery wells with a true vertical depth greater than 4,000 metres whose surface locations are at least 20 kilometres away from the surface location of any well drilled into a recognized pool within the same formation;
- *Coalbed Gas Royalty Reduction and Credit Program* providing a royalty reduction for coalbed gas wells with average daily production less than 17,000 m<sup>3</sup> as well as a royalty credit for coalbed gas wells equal to \$50,000 for wells drilled on Crown land and a tax credit equal to \$30,000 for wells drilled on freehold land;
- *Marginal Royalty Reduction Program* providing a monthly royalty reduction for low productivity natural gas wells with an average daily rate of production less than 23 m<sup>3</sup> for every metre of marginal well depth in the first 12 months of production. To be eligible, wells must have been spudded after May 31, 1998 and the first month of marketable gas production must have occurred between June 2003 and August 2008. Once a well passes the initial eligibility test, a reduction is realized in each month that average daily production is less than 25,000 m<sup>3</sup>;
- *Ultra-Marginal Royalty Reduction Program* providing royalty reductions for low productivity, shallow natural gas wells. Vertical wells must be less than 2,500 metres and horizontal wells less than 2,300 metres to be eligible. Production in the first 12 months ending after January 2007 must be less than 17 m<sup>3</sup> per metre of depth for exploratory wildcat wells and less than 11 m<sup>3</sup> per metre of depth for development wells and exploratory outpost wells. The well must have been spudded or re-entered after December 31, 2005. A reduction is realized in each month that average daily production is less than 60,000 m<sup>3</sup>. Horizontal wells that are spud on or after April 1, 2014 are not eligible for the Ultra-Marginal Royalty Reduction Program due to the potential for overlap with shallower horizontal wells eligible for a royalty credit under the Deep Well Royalty Credit Program; and
- *Net Profit Royalty Reduction Program* providing reduced initial royalty rates to facilitate the development and commercialization of technically complex resources such as coalbed gas, tight gas, shale gas and enhanced-recovery projects, with higher royalty rates applied once capital costs have been recovered.

Oil produced from an oil well that is located on either Crown or freehold land and completed in a new pool discovered subsequent to June 30, 1974 may be exempt from the payment of a royalty for the first 36 months of production or 11,450 m<sup>3</sup> of production, whichever comes first.

The Government of British Columbia also maintains an Infrastructure Royalty Credit Program that provides royalty credits for up to 50 percent of the cost of certain approved road construction or pipeline infrastructure projects intended to facilitate increased oil and gas exploration and production in under-developed areas and to extend the drilling season.

### **Saskatchewan**

In Saskatchewan, the Crown owns approximately 70 percent of the oil and gas rights. For the Crown lands, taxes (the "**Resource Surcharge**") and royalties are applicable to revenue generated by corporations focused on oil and gas operations.

A Resource Surcharge on the value of sales of oil, natural gas, potash, uranium and coal in Saskatchewan is levied under authority of *The Corporation Capital Tax Act*. For resource corporations, the Resource Surcharge rate is three percent of the value of sales of all potash, uranium and coal produced in Saskatchewan, and oil and natural gas produced from wells drilled in Saskatchewan prior to October 1, 2002. For oil and natural gas produced from wells drilled in Saskatchewan after September 30, 2002, the Resource Surcharge rate is 1.7 percent of the value of sales. The Resource Surcharge applies to resource trusts in addition to resource corporations.

The amount payable as a Crown royalty or a freehold production tax in respect of oil depends on the type and vintage of oil, the quantity of oil produced in a month, the value of the oil produced and specified adjustment factors determined monthly by the provincial government. For Crown royalty and freehold production tax purposes, conventional oil is divided into types, being "heavy oil", "southwest designated oil" or "non-heavy oil other than southwest designated oil". The vintage of oil being "fourth tier oil", "third tier oil", "new oil" and "old oil" depends on the finished drilling date of a well and is applied to each of the three crude oil types slightly differently:

- Heavy oil is classified as third tier oil (produced from a vertical well having a finished drilling date on or after January 1, 1994 and before October 1, 2002 or incremental oil from new or expanded waterflood projects with a commencement date on or after January 1, 1994 and before October 1, 2002), fourth tier oil (having a finished drilling date on or after October 1, 2002 or incremental oil from new or expanded waterflood projects with a commencement date on or after October 1, 2002) or new oil (conventional oil that is not classified as third tier oil or fourth tier oil).
- Southwest designated oil uses the same definition of fourth tier oil but third tier oil is defined as conventional oil produced from a vertical well having a finished drilling date on or after February 9, 1998 and before October 1, 2002 or incremental oil from new or expanded waterflood projects with a commencement date on or after February 9, 1998 and before October 1, 2002 and new oil is defined as conventional oil produced from a horizontal well having a finished drilling date on or after February 9, 1998 and before October 1, 2002.
- For non-heavy oil other than southwest designated oil, the same classification as heavy oil is used but new oil is defined as conventional oil produced from a vertical well completed after 1973 and having a finished drilling date prior to 1994, conventional oil produced from a horizontal well having a finished drilling date on or after April 1, 1991 and before October 1, 2002, or incremental oil from new or expanded waterflood projects with a commencement date on or after January 1, 1974 and before 1994 whereas old oil is defined as conventional oil not classified as third or fourth tier oil or new oil.

Production tax rates for freehold production are determined by first determining the Crown royalty rate and then subtracting the Production Tax Factor ("PTF") applicable to that classification of oil. Currently the PTF is 6.9 for old oil, 10.0 for new oil and third tier oil and 12.5 for fourth tier oil. The minimum rate for freehold production tax is zero.

Base prices are used to establish lower limits in the price-sensitive royalty structure for conventional oil and apply at a reference well production rate of 100 m<sup>3</sup> for old oil, new oil and third tier oil, and 250 m<sup>3</sup> per month for fourth tier oil. Where average wellhead prices are below the established base prices of \$100 per m<sup>3</sup> for third and fourth tier oil and \$50 per m<sup>3</sup> for new oil and old oil, base royalty rates are applied. Base royalty rates are five percent for all fourth tier oil, ten percent for heavy oil that is third tier oil or new oil, 12.5 percent for southwest designated oil that is third tier oil or new oil, 15 percent for non-heavy oil other than southwest designated oil that is third tier or new oil, and 20 percent for old oil. Where average wellhead prices are above base prices, marginal royalty rates are applied to the proportion of production that is above the base oil price. Marginal royalty rates are 30 percent for all fourth tier oil, 25 percent for heavy oil that is third tier oil or new oil, 35 percent for southwest designated oil that is third tier oil or new oil, 35 percent for non-heavy oil other than southwest designated oil that is third tier or new oil, and 45 percent for old oil.

The amount payable as a Crown royalty or a freehold production tax in respect of natural gas production 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 and the classification of the natural gas. Like conventional oil, natural gas may be classified as "non-associated gas" (gas produced from gas wells) or "associated gas" (gas produced from oil wells) and royalty rates are determined according to the finished drilling date of the respective well. Non-associated gas is classified as new gas (having a finished drilling date before February 9, 1998 with a first production date on or after October 1, 1976), third tier gas (having a finished drilling date on or after February 9, 1998 and before October 1, 2002), fourth tier gas (having a finished drilling date on or after October 1, 2002) and old gas (not classified as either third tier, fourth tier or new gas). A similar classification is used for associated gas except that the classification of old gas is not used, the definition of fourth tier gas also includes production from oil wells with a finished drilling date prior to October 1, 2002, where the individual oil well has a gas-oil production ratio in any month of at least 3,500 m<sup>3</sup> of gas for every m<sup>3</sup> of oil and new gas is defined as oil produced from a well with a finished drilling date before February 9, 1998 that received special approval, prior to October 1, 2002, to produce oil and gas concurrently without gas-oil ratio penalties. Natural gas liquids and by-products recovered at gas processing plants are not subject to a royalty. Gas liquids which are produced and measured at the wellhead are treated as crude oil for royalty purposes.

On December 9, 2010, the Government of Saskatchewan enacted the Freehold Oil and Gas Production Tax Act, 2010 with the intention to facilitate the efficient payment of freehold production taxes by industry. Two new regulations with respect to this legislation are: (i) The Freehold Oil and Gas Production Tax Regulations, 2012 which sets out the terms and conditions under which the taxes are calculated and paid; and (ii) The Recovered Crude Oil Tax Regulations, 2012 which sets out the terms and conditions under which taxes on recovered crude oil that was delivered from a crude oil recovery facility on or after March 1, 2012 are to be calculated and paid.

As with conventional oil production, base prices based on a well reference rate of 250,000 m<sup>3</sup> per month are used to establish lower limits in the price-sensitive royalty structure for natural gas. Where average field-gate prices are below the established base prices of \$1.35 per gigajoule for third and fourth tier gas and \$0.95 per gigajoule for new gas and old gas, base royalty rates are applied. Base royalty rates are five percent for all fourth tier gas, 15 percent for third tier or new gas, and 20 percent for old gas. Where average wellhead prices are above base prices, marginal royalty rates are applied to the proportion of production that is above the base gas price. Marginal royalty rates are 30 percent for all fourth tier gas, 35 percent for third tier and new gas, and 45 percent for old gas. The current regulatory scheme provides for certain differences with respect to the administration of fourth tier gas, which is associated gas.

The Government of Saskatchewan currently provides a number of targeted incentive programs. These include both royalty reduction and incentive volume programs, including the following:

- *Royalty/Tax Incentive Volumes for Vertical Oil Wells Drilled on or after October 1, 2002* providing reduced Crown royalty (a Crown royalty rate of the lesser of fourth tier oil Crown royalty rate and 2.5 percent) and freehold tax rates (a freehold production tax rate of zero percent) on incentive volumes of 8,000 m<sup>3</sup> for deep development vertical oil wells, 4,000 m<sup>3</sup> for non-deep exploratory vertical oil wells and 16,000 m<sup>3</sup> for deep exploratory vertical oil wells (more than 1,700 metres or within certain formations) and after the incentive volume is produced, the oil produced will be subject to the fourth tier royalty tax rate;
- *Royalty/Tax Incentive Volumes for Exploratory Gas Wells Drilled on or after October 1, 2002* providing reduced Crown royalty (a Crown royalty rate of the lesser of fourth tier oil Crown royalty rate and 2.5 percent) and freehold tax rates (a freehold production tax rate of zero percent) on incentive volumes of 25,000,000 m<sup>3</sup> for qualifying exploratory gas wells;
- *Royalty/Tax Incentive Volumes for Horizontal Oil Wells Drilled on or after October 1, 2002* providing reduced Crown royalty (a Crown royalty rate of the lesser of fourth tier oil Crown royalty rate and 2.5 percent) and freehold tax rates (a freehold production tax rate of zero percent) on incentive volumes of 6,000 m<sup>3</sup> for non-deep horizontal oil wells and 16,000 m<sup>3</sup> for deep horizontal oil wells (more than 1,700 metres total vertical depth or within certain formations) and after the incentive volume is produced, the oil produced will be subject to the fourth tier royalty tax rate;
- *Royalty/Tax Incentive Volumes for Horizontal Gas Wells drilled on or after June 1, 2010 and before April 1, 2013* providing for a classification of the well as a qualifying exploratory gas well and resulting in a reduced Crown royalty (a Crown royalty rate of the lesser of fourth tier oil Crown royalty rate and 2.5 percent) and freehold tax rates (a freehold production tax rate of zero percent) on incentive volumes of 25,000,000 m<sup>3</sup> for horizontal gas wells and after the incentive volume is produced, the gas produced will be subject to the fourth tier royalty tax rate;
- *Royalty/Tax Regime for Incremental Oil Produced from New or Expanded Waterflood Projects Implemented on or after October 1, 2002* whereby incremental production from approved waterflood projects is treated as fourth tier oil for the purposes of Crown royalty and freehold tax calculations;
- *Royalty/Tax Regime for Enhanced Oil Recovery Projects (Excluding Waterflood Projects) Commencing prior to April 1, 2005* providing lower Crown royalty and freehold tax determinations based in part on the profitability of EOR projects during and subsequent to the payout of the EOR operations;
- *Royalty/Tax Regime for Enhanced Oil Recovery Projects (Excluding Waterflood Projects) Commencing on or after April 1, 2005* providing a Crown royalty of one percent of gross revenues on EOR projects pre-payout and 20 percent of EOR operating income post-payout and a freehold production tax of zero percent pre-payout and eight percent post-payout on operating income from EOR projects; and
- *Royalty/Tax Regime for High Water-Cut Oil Wells* designed to extend the product lives and improve the recovery rates of high water-cut oil wells and granting third tier oil royalty/tax rates with a Saskatchewan Resource Credit of 2.5 percent for oil produced prior to April 2013 and 2.25 percent for oil produced on or after April 1, 2013 to incremental high water-cut oil production resulting from qualifying investments made to rejuvenate eligible oil wells and/or associated facilities.

On June 22, 2011, the Government of Saskatchewan released the Upstream Petroleum Industry Associated Gas Conservation Standards, which are designed to reduce emissions resulting from the flaring and venting of associated gas (the "**Associated Natural Gas Standards**"). The Associated Natural Gas Standards were jointly developed with industry and the implementation of such standards commenced on July 1, 2012 for new wells and facilities licensed on or after such date. The new standards apply to existing licensed wells and facilities on July 1, 2015.

Effective April 1, 2014, the Saskatchewan Ministry of the Economy streamlined fees related to licences and applications in the oil and gas sector by eliminating 11 different licensing fees, which resulted in an aggregate of 20,000 fee transactions per year, and replacing them with a single annual levy based on a company's production and number of wells. Effective October 27, 2016, the Saskatchewan Ministry of the Economy streamlined a further 20 different service fees, and implemented a Crown Minerals Electronic Registry for oil and gas tenure in Saskatchewan that will provide for certainty of tenure comparable to Alberta and reduce the administrative burden.

## **Nova Scotia**

The Government of Nova Scotia has established a generic royalty regime in respect of oil and gas produced from offshore Nova Scotia based on revenues and profits. Such regime contemplates a multi-tier royalty in which the royalty rate fluctuates when certain threshold levels of rates of return on capital have been reached and offers lower royalties for a first project in a new area, being a "high risk project". Notwithstanding the generic royalty regime, royalties in respect of offshore Nova Scotia oil and gas production may be determined contractually between the participant and the Government of Nova Scotia.

## **Land Tenure**

The respective provincial governments predominantly own the rights to crude oil and natural gas located in the western provinces. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences, and permits for varying terms, and on conditions set forth in provincial legislation including requirements to perform specific work or make payments. Private ownership of oil and natural gas also exists in such provinces and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

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. The Government of British Columbia expanded its policy of deep rights reversion for leases issued after March 29, 2007, to provide for the reversion of both shallow and deep formations that cannot be shown to be capable of production at the end of the primary term.

Alberta also has a policy of "shallow rights reversion" which provides for the reversion to the Crown of mineral rights to shallow, non-productive geological formations for all leases and licences issued after January 1, 2009, at the conclusion of the primary term of the lease or licence.

## **Production and Operation Regulations**

The oil and natural gas industry in Canada is highly regulated and subject to significant control by provincial regulators. Regulatory approval is required for, among other things, the drilling of oil and natural gas wells, construction and operation of facilities, the storage, injection and disposal of substances and the abandonment and reclamation of well-sites. In order to conduct oil and gas operations and remain in good standing with the applicable provincial regulator, 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 with such legislation, regulations, orders, directives or other directions can be costly and a breach of the same may result in fines or other sanctions.

## **Environmental Regulation**

The 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 is subject to governmental review and revision from time to time. Such legislation provides for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with certain oil and 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 legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licences and authorizations, civil liability and the imposition of material fines and penalties. In addition to these specific, known requirements, future changes to environmental legislation, including anticipated legislation for air pollution and GHG emissions, may impose further requirements on operators and other companies in the oil and natural gas industry.

## **Federal**

Canadian environmental regulation is the responsibility of the Federal Government 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. The *Canadian Environmental Protection Act, 1999* and the *Canadian Environmental Assessment Act, 2012* provide the foundation for the Federal Government to protect the environment and cooperate with provinces to do the same.

Pursuant to the Prosperity Act, the Government of Canada amended or repealed several pieces of federal environmental legislation and in addition, created a new federal environmental assessment regime that came in to force on July 6, 2012. The changes to the environmental legislation under the Prosperity Act are intended to provide for more efficient and timely environmental assessments of projects that previously had been subject to overlapping legislative jurisdiction.

On June 20, 2016, the Federal Government launched a review of current environmental and regulatory processes with a focus on rebuilding trust in the environmental assessment processes, modernizing the NEB, and introducing modernized safeguards to both the *Fisheries Act* and the *Navigation Protection Act*. An expert panel has been convened and is expected to complete its work by March 31, 2017. At such

time, the Minister of Environment and Climate Change will consider the recommendations in the panel's report and identify next steps to improve federal environmental processes, which is expected to take place during the summer/fall of 2017. Until this process is complete, the Federal Government's interim principles released January 27, 2016 will continue to guide decision-making authorities for projects currently undergoing environmental assessment. The Federal Government has not provided any indication on what changes, if any, will be implemented or when, but increased delays and uncertainty surrounding the environmental assessment process should be expected for large projects.

In a further development, on November 29, 2016, the Government of Canada announced that it would introduce legislation by spring 2017 to formalize a moratorium for crude oil tankers on British Columbia's north coast. It is unclear how the proposed moratorium may affect ongoing LNG export projects currently under consideration and development. On the same day, the Government of Canada also approved, subject to a number of conditions, the Trans Mountain Pipeline system expansion backed by Kinder Morgan Canada as well as Enbridge Inc.'s plan to replace its Line 3 pipeline system, while also rejecting Enbridge Inc.'s proposed Northern Gateway project. On January 11, 2017, the Government of British Columbia confirmed that the conditions to the approval of the Trans Mountain Pipeline have been satisfied. Additionally, the new administration in the United States has indicated a willingness to revisit other pipeline projects that had been previously rejected.

## **Alberta**

The AER is the single regulator responsible for all energy development in Alberta. The AER ensures 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 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. The following frameworks, plans and policies form the basis of Alberta's Integrated Resource Management System ("**IRMS**"). The IRMS method 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.

In December 2008, the Government of Alberta released a new land use policy for surface land in Alberta, the Alberta Land Use Framework (the "**ALUF**"). The ALUF 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.

Proclaimed in force in Alberta on October 1, 2009, the *Alberta Land Stewardship Act* (the "**ALSA**") provides the legislative authority for the Government of Alberta to implement the policies contained in the ALUF. Regional plans established under the ALSA are deemed to be legislative instruments equivalent to regulations and will be binding on the Government of Alberta and provincial regulators, including those governing the oil and gas industry. In the event of a conflict or inconsistency between a regional plan and another regulation, regulatory instrument or statutory consent, the regional plan will prevail. Further, the ALSA requires local governments, provincial departments, agencies and administrative bodies or tribunals to review their regulatory instruments and make any appropriate changes to ensure that they comply with an adopted regional plan. The ALSA also contemplates the amendment or extinguishment of previously issued statutory consents such as regulatory permits, licences, registrations, approvals and authorizations for the purpose of achieving or maintaining an objective or policy resulting from the implementation of a regional plan. Among the measures to support the goals of the regional plans contained in the ALSA are conservation easements, which can be granted for the protection, conservation and enhancement of land; and conservation directives, which are explicit declarations contained in a regional plan to set aside specified lands in order to protect, conserve, manage and enhance the environment.

On August 22, 2012, the Government of Alberta approved the Lower Athabasca Regional Plan ("**LARP**") which came into force on September 1, 2012. The LARP is the first of seven regional plans developed under the ALUF. LARP covers a region in the northeastern corner of Alberta that is approximately 93,212 square kilometres in size. The region includes a substantial portion of the Athabasca oil sands area, which contains approximately 82 percent of the province's oil sands resources and much of the Cold Lake oil sands area.

LARP establishes six new conservation areas and nine new provincial recreation areas. In conservation and provincial recreation areas, conventional oil and gas companies with pre-existing tenure may continue to operate. Any new petroleum and gas tenure issued in conservation and provincial recreation areas will include a restriction that prohibits surface access. In contrast, oil sands companies' tenure has been (or will be) cancelled in conservation areas and no new oil sands tenure will be issued. While new oil sands tenure will be issued in provincial recreation areas, new and existing oil sands tenure will prohibit surface access.

In July 2014, the Government of Alberta approved the South Saskatchewan Regional Plan ("SSRP") which came into force on September 1, 2014. The SSRP is the second regional plan developed under the ALUF. The SSRP covers approximately 83,764 square kilometres and includes 44 percent of the provincial population.

The SSRP creates four new and four expanded conservation areas, and two new and six expanded provincial parks and recreational areas. Similar to LARP, the SSRP will honour existing petroleum and natural gas tenure in conservation and provincial recreational areas. However, any new petroleum and natural gas tenures sold in conservation areas, provincial parks, and recreational areas will prohibit surface access. However, oil and gas companies must minimize impacts of activities on the natural landscape, historic resources, wildlife, fish and vegetation when exploring, developing and extracting the resources. Freehold mineral rights will not be subject to this restriction.

Phase 1 Consultation of the North Saskatchewan Regional Plan ("NSRP") has been completed and the Regional Advisory Council is currently preparing its Recommendation to Government report. The NSRP is located in central Alberta and is approximately 85,780 square kilometres in size and affects activities in central Alberta, and encompasses an area between the province's borders with British Columbia and Saskatchewan. The Upper Peace Region Plan, Lower Peace Region Plan, Red Deer Region Plan and Upper Athabasca Region Plan have not been started.

### **British Columbia**

In British Columbia, the *Oil and Gas Activities Act* (the "OGAA") impacts conventional oil and gas producers, shale gas producers and other operators of oil and 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 oil and 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 an oil and 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.

### **Saskatchewan**

In May 2011, the Government of Saskatchewan passed changes to *The Oil and Gas Conservation Act* ("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 ("OGCR") and The Petroleum Registry and Electronic Documents Regulations ("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 the Petroleum Registry of Alberta.

### Liability Management Rating Programs

#### **Alberta**

In 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 oil and gas wells, facilities and pipelines. *Alberta's Oil and Gas Conservation Act* ("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 defunct 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 failure to post the required security deposit 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.

Made effective in three phases, from May 1, 2013 to August 1, 2015, the AER implemented important changes to the AB LLR Program (the "Changes") that resulted in a significant increase in the number of oil and gas companies in Alberta that are required to post security. The Changes affect the deemed parameters and costs used in the formula that calculates the ratio of deemed assets to deemed liabilities under the AB LLR Program, increasing a licensee's deemed liabilities and rendering the industry average netback factor more sensitive to asset value fluctuations. The Changes stem from concern that the previous regime significantly underestimated the environmental liabilities of licensees.

On June 20, 2016, the AER issued *Bulletin 2016-16, Licensee Eligibility-Alberta Energy Regulator Measures to Limit Environmental Impacts Pending Regulatory Changes to Address the Redwater Decision ("Bulletin 16")* in an urgent response to a decision from the Alberta Court of Queen's Bench, which is currently under appeal with the Court of Appeal of Alberta. In *Redwater Energy Corporation (Re)*, 2016 ABQB 278 ("*Redwater*"), Chief Justice Wittman found that there was an operational conflict between the abandonment and reclamation provisions of the OGCA and the *Bankruptcy and Insolvency Act ("BIA")*, and that receivers and trustees have the right to renounce assets within insolvency proceedings. Such a conflict renders the AER's legislated authority unenforceable to impose abandonment orders against licensees or to require a licensee to pay a security deposit before approving a transfer when such a licensee is insolvent. Effectively, this means that abandonment costs will be borne by the industry-funded Orphan Well Fund or the province in these instances because any resources of the insolvent licensee will first be used to satisfy secured creditors under the *BIA*. *Bulletin 16* provides interim rules to govern while the case is appealed and while the Government of Alberta can develop appropriate regulatory measures to adequately address environmental liabilities. Three changes were implemented to minimize the risk to Albertans:

- The AER will consider and process all applications for licence eligibility under Directive 067: Applying for Approval to Hold EUB Licences as non-routine and may exercise its discretion to refuse an application or impose terms and conditions on a licensee eligibility approval if appropriate in the circumstances.
- For holders of existing but previously unused licence eligibility approvals, prior to approval of any application (including licence transfer applications), the AER may require evidence that there have been no material changes since approving the licence eligibility. This may include evidence that the holder continues to maintain adequate insurance and that the directors, officers, and/or shareholders are substantially the same as when licence eligibility was originally granted.
- As a condition of transferring existing AER licences, approvals, and permits, the AER will require 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.

In order to clarify and revise the interim rules in *Bulletin 16*, the AER issued *Bulletin 2016-21: Revision and Clarification on Alberta Energy Regulator's Measures to Limit Environmental Impacts Pending Regulatory Changes to Address the Redwater Decision ("Bulletin 21")* on July 8, 2016 and reaffirmed its position that an LMR of 1.0 is not sufficient to ensure that licensees will be able to address their obligations throughout the life cycle of energy development, and 2.0 remains the requirement for transferees. However, *Bulletin 21* did provide the AER with additional flexibility to permit licensees to acquire additional AER-licensed assets if:

- The licensee already has an LMR of 2.0 or higher;
- The acquisition will improve the licensee's LMR to 2.0 or higher; or
- The licensee is able to satisfy its obligations, notwithstanding an LMR below 2.0, by other means.

The AER provided no indication of what other means would be considered. In the short term the interim measures caused delays in completing transactions and reduced the pool of possible purchasers, however, transactions have been approved following a more rigorous review by the AER, despite a transferee's LMR not meeting the interim requirement. The Alberta Court of Appeal heard the appeal of the *Redwater* decision on October 11, 2016, with the Court reserving its decision.

The AER 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 percent 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 AER announced that from April 1, 2015 to April 1, 2016, the number of noncompliant wells subject to the IWCP fell from 25,792 to 17,470, with 76 percent of licensees operating in the province having met their annual quota.

#### **British Columbia**

In British Columbia, the Commission oversees the Liability Management Rating Program (the "*BC LMR Program*"), designed to manage public liability exposure related to oil and 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 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 will be considered high risk and reviewed for a security deposit. Permit holders who fail to submit the required security deposit within the allotted timeframe may be in non-compliance with the OGAA.

#### **Saskatchewan**

In Saskatchewan, the Ministry of the Economy administers 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 to post a security deposit. The ratio of deemed assets to deemed liabilities is assessed once each month for all licensees of oil, gas and service wells and upstream oil and gas facilities. On August 19, 2016, the Ministry of the Economy released a notice to all operators that it would follow the AER's interim rules by processing all licence transfer applications as non-routine until further notice.

## Climate Change Regulation

### **Federal**

Climate change regulation at both the federal and provincial level has the potential to significantly affect the regulatory environment of the oil and natural gas industry in Canada. Such regulations, surveyed below, impose certain costs and risks on the industry.

On April 26, 2007, the Government of Canada released "Turning the Corner: An Action Plan to Reduce Greenhouse Gases and Air Pollution" (the "**Action Plan**") which set forth a plan for regulations to address both GHGs and air pollution. An update to the Action Plan, "Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions" was released on March 10, 2008 (the "**Updated Action Plan**"). The Updated Action Plan outlines emissions intensity-based targets for application to regulated sectors on a facility-specific basis, sector-wide basis or company-by-company basis. Although the intention was for draft regulations aimed at implementing the Updated Action Plan to become binding on January 1, 2010, the only regulations being implemented are in the transportation and electricity sectors.

As a signatory to the *United Nations Framework Convention on Climate Change* (the "**UNFCCC**") and a participant to the Copenhagen Accord (a non-binding agreement created by the UNFCCC), the Government of Canada announced on January 29, 2010 that it will seek a 17 percent reduction in GHG emissions from 2005 levels by 2020; however, the GHG emission reduction targets are not binding. In May 2015, Canada submitted its Intended Nationally Determined Contribution ("**INDC**") to the UNFCCC. INDCs were communicated prior to the 2015 United Nations Climate Change Conference, held in Paris, France, which led to the Paris Agreement that came into force November 4, 2016 (the "**Paris Agreement**"). Among other items, the Paris Agreement contains the actions and targets that individual countries will undertake to help keep global temperatures from rising more than 2° Celsius and to pursue efforts to limit below 1.5° Celsius. The Government of Canada ratified the Paris Agreement on December 12, 2016, and pursuant to the agreement, Canada's INDC became its Nationally Determined Contributions ("**NDC**"). As a result, the Government of Canada replaced its INDC of a 17 percent reduction target established in the Copenhagen Accord with an NDC of 30 percent reduction below 2005 levels by 2030.

On June 29, 2016, the North American Climate, Clean Energy and Environment Partnership was announced among Canada, Mexico and the United States, which announcement included an action plan for achieving a competitive, low-carbon and sustainable North American economy. The plan includes setting targets for clean power generation, committing to implement the Paris Agreement, setting out specific commitments to address certain short-lived climate pollutants, and the promotion of clean and efficient transportation.

Additionally, on December 9, 2016, the Government of Canada formally announced the Pan-Canadian Framework on Clean Growth and Climate Change. As a result, the Federal Government will implement a Canada-wide carbon pricing scheme beginning in 2018. This may be implemented through either a cap and trade system or a carbon tax regime at the option of each province or territory. The Federal Government will impose a price on carbon of \$10 per tonne on any province or territory which fails to implement its own system by 2018. This amount will increase by \$10 annually until it reaches \$50 per tonne in 2022 at which time the program will be reviewed.

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.

### **Alberta**

As part of its efforts to reduce GHG emissions, Alberta introduced legislation to address GHG emissions: the *Climate Change and Emissions Management Act* (the "**CCEMA**") enacted on December 4, 2003 and amended through the *Climate Change and Emissions Management Amendment Act*, which received royal assent on November 4, 2008. The accompanying regulations include the *Specified Gas Emitters Regulation* ("**SGER**"), which imposes GHG limits, and the *Specified Gas Reporting Regulation*, which imposes GHG emissions reporting requirements. Alberta is the first jurisdiction in North America to impose regulations requiring large facilities in various sectors to reduce their GHG emissions. The SGER applies to facilities emitting more than 100,000 tonnes of GHG emissions in 2003 or any subsequent year ("**Regulated Emitters**"), and requires reductions in GHG emissions intensity (e.g. the quantity of GHG emissions per unit of production) from emissions intensity baselines established in accordance with the SGER.

On June 25, 2015, the Government of Alberta renewed the SGER for a period of two years with significant amendments while Alberta's newly formed Climate Advisory Panel conducted a comprehensive review of the province's climate change policy. As of 2015, Regulated Emitters are required to reduce their emissions intensity by two percent from their baseline in the fourth year of commercial operation, four percent of their baseline in the fifth year, six percent of their baseline in the sixth year, eight percent of their baseline in the seventh year, ten percent of their baseline in the eighth year, and 12 percent of their baseline in the ninth or subsequent years. These reduction targets will increase, meaning that Regulated Emitters in their ninth or subsequent years of commercial operation must reduce their emissions intensity from their baseline by 15 percent in 2016 and 20 percent in 2017.

A Regulated Emitter can meet its emissions intensity targets through a combination of the following: (1) producing its products with lower carbon inputs, (2) purchasing emissions offset credits from non-regulated emitters (generated through activities that result in emissions reductions in accordance with established protocols), (3) purchasing emissions performance credits from other Regulated Emitters that earned credits through the reduction of their emissions below the 100,000 tonne threshold, (4) cogeneration compliance adjustments, and (5) by contributing to the Climate Change and Emissions Management Fund (the "**Fund**"). Contributions to the Fund are made at a rate of \$15 per tonne of GHG emissions, increasing to a rate of \$20 per tonne of GHG emissions in 2016 and \$30 per tonne of GHG emissions in 2017. Proceeds from the Fund are directed at testing and implementing new technologies for greening energy production.

On November 22, 2015, as a result of the Climate Advisory Panel's Climate Leadership report, the Government of Alberta announced its Climate Leadership Plan. On June 7, 2016, the *Climate Leadership Implementation Act* ("**CLIA**") was passed into law. The *CLIA* enacted the *Climate Leadership Act* ("**CLA**") introducing a carbon tax on all sources of GHG emissions, subject to certain exemptions. An initial economy-wide levy of \$20 per tonne was implemented on January 1, 2017, increasing to \$30 per tonne in January of 2018. All fuel consumption-including gasoline and natural gas-will be subject to the levy, with certain exemptions, and directors of a corporation may be held jointly and severally liable with a corporation when the corporation fails to remit an owed carbon levy. Regulated Emitters will remain subject to the *SGER* framework until the end of 2017 and are exempt from paying the carbon levy on fuels used in operations until this time. Upon the expiry of the *SGER*, the Government of Alberta intends to transition to a proposed *Carbon Competitiveness Regulation*, in which sector specific output-based carbon allocations will be used to ensure competitiveness. A 100 megatonne per year limit for GHG emissions was implemented for oil sands operations, which currently emit roughly 70 megatonnes per year. This cap exempts new upgrading and cogeneration facilities, which are allocated a separate ten megatonne limit. Regulations accompanying the *CLIA* have not yet been released.

There are certain exemptions to the carbon levy imposed by the *CLA*. Until 2023, fuels consumed, flared or vented in a production process by conventional oil and gas producers will be exempt from the carbon levy. An exemption also applies for biofuels and fuels sold for export. In addition, marked fuels used in farming operations as well as personal and band uses by First Nations are exempt.

The passing of the *CLIA* is the first step towards executing the Climate Leadership Plan (other legislation is still pending). In addition to enacting the *CLA*, the *CLIA* also enacted the *Energy Efficiency Alberta Act*, which enables the creation of Energy Efficiency Alberta, a new Crown corporation to support and promote energy efficiency programs and services for homes and businesses.

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

Alberta is 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.

Under the *SGER* and based on 2015 emissions, we retired Emission Performance Credits from inventory, in the amount of \$187,500, to meet compliance for our Quirk Creek Gas Plant. We were not required to purchase Emission Performance Credits for the Olds Gas Plant and Judy Creek Gas Conservation Plant as these facilities met the reduction requirements of the *SGER* and subsequently received carbon credits for this reduction.

### **British Columbia**

British Columbia launched its Climate Action Plan in 2008 and met its first interim emission reduction targets in 2012. In February 2008, the Government of British Columbia announced a revenue-neutral carbon tax that took effect July 1, 2008. The tax is consumption-based and applied at the time of retail sale or consumption of virtually all fossil fuels purchased or used in British Columbia. The current tax level is \$30 per tonne of GHG emissions. The final scheduled increase took effect on July 1, 2012, wherein the Government of British Columbia froze the tax level to allow other jurisdictions time to adopt comparable carbon pricing mechanisms. In order to make the tax revenue-neutral, the Government of British Columbia has implemented tax credits and reductions in order to offset the tax revenues that the Government of British Columbia would otherwise receive from the tax.

Further, on April 3, 2008, the Government of British Columbia introduced the *Greenhouse Gas Reduction (Cap and Trade) Act* (the "**Cap and Trade Act**"), which received royal assent on May 29, 2008 and partially came into force by regulation of the Lieutenant Governor in Council. It sets a province-wide target of a 33 percent reduction in the 2007 level of GHG emissions by 2020 and an 80 percent reduction by 2050. Unlike the emissions intensity approach taken by the Federal Government and the Government of Alberta, the Cap and Trade Act establishes an absolute cap on GHG emissions. The *Greenhouse Gas Emission Reporting Regulation*, implemented under the authority of the Cap and Trade Act, sets out the requirements for the reporting of the GHG emissions from facilities in British Columbia emitting 10,000 tonnes or more of carbon dioxide equivalent emissions per year beginning on January 1, 2010. Those reporting operations with emissions of 25,000 tonnes or greater are required to have emissions reports verified by a third party. The reporting system for large emitters of GHGs has since been streamlined by the *Greenhouse Gas Industrial Reporting and Control Act* (the "**GGIRCA**") and its associated regulations that came into force on January 1, 2016. The *GGIRCA* sets out benchmarked performance standards for different industrial facilities and sectors, provides for emissions offsets through the purchase of emission credits or emission offsetting projects, among other measures, and replaces the *Cap and Trade Act*.

For 2015 operations, we had only one facility (Groundbirch) exceeding the 10,000 tonne CO<sub>2</sub> threshold as a result, we are required to quantify and report our emissions.

Following the 2012 Budget, the Government of British Columbia undertook a comprehensive review of the carbon tax and its impact on British Columbians. The review covered all aspects of the carbon tax, including revenue neutrality, and considered the impact on the competitiveness of British Columbia businesses such as those in the agriculture sector, and in particular, British Columbia's food producers. After the review, the Government of British Columbia confirmed that it will keep its revenue-neutral carbon tax-the current carbon tax rates, tax base will be maintained, and revenues will continue to be returned through tax reductions.

On August 19, 2016, the Government of British Columbia unveiled its Climate Leadership Plan with a goal to reduce net annual GHG emissions by up to 25 million tonnes below current forecasts by 2050, and reaffirmed that it will achieve its 2050 target of an 80 percent reduction in emissions from 2007 levels. In addition to various measures across the economy that are designed to incentivize the growth of the renewable energy sector, the use of low GHG emitting technologies, and the improvement of energy efficiency, among other goals, the Government of British Columbia will soon implement a formal policy to regulate carbon capture and storage projects. Further, the Climate Leadership Plan sets out a strategy to reduce methane emissions in the upstream natural gas sector, beginning with a "Legacy" phase that targets a 45 percent reduction in fugitive and vented emissions by 2025 for facilities built before January 1, 2015, followed by a "Transition" phase for facilities built between 2015 and 2018 that involves a new offset protocol and a Clean Infrastructure Royalty Credit Program along with other incentives, and finally a "Future" phase that will implement standards going forward.

### **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 received Royal Assent on May 20, 2010 and will come into force on proclamation. The MRGGA establishes a framework for achieving the provincial target of a 20 percent reduction in GHG emissions from 2006 levels by 2020. Although the MRGGA and related regulations have yet to be proclaimed in force, draft versions indicate that, the Government of Saskatchewan will permit the use of pre-certified investment credits, early action credits and emissions offsets in compliance, similar to the federal climate change initiatives. It remains unclear whether the scheme implemented by the MRGGA will be based on emissions intensity or an absolute cap on emissions.

### **Nova Scotia**

The Province of Nova Scotia has set a goal of lowering greenhouse gas emissions by ten percent below 1990 levels by 2020 and has implemented the Environmental Goals and Sustainable Prosperity Act. The Crown must report annually the amount of reductions achieved in the province but there is no mechanism for measuring compliance nor are there any consequences for failing to meet the goal.

### **General Discussion**

At present, we are not paying any direct costs or penalties as a result of air emission exceedances other than the purchase of credits in relation to our Quirk Creek gas plant. However, the direct and indirect costs of the various GHG regulations, existing and proposed, may at some time and under certain conditions adversely affect our business, operations and financial results. Equipment that meets future emission standards may not be available on an economic basis and other compliance and/or engineering methods to reduce our emissions and associated emissions intensity to future required levels may temporarily increase operating costs. Offset, performance or fund credits may not be available for acquisition or may not be available on an economic basis. Any failure to meet emission reduction compliance obligations requirements may materially adversely affect our business and may result in an increased cost for purchasing offset carbon credits until compliant. There is also a risk that one or more levels of government could impose additional emissions or emissions intensity reduction requirements or taxes on emissions created by us or by 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.

## **RISK FACTORS**

If any of the following risks occur, our production, revenues and financial condition could be materially impaired, with a resulting decrease in the market price of, our Common Shares. As a result, the trading price of our Common Shares could decline, and you could lose all or part of your investment. **Additional risks are described under the heading "Business Risks" in our Management's Discussion and Analysis for the year ended December 31, 2016.**

**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 unrelated to our performance could include macroeconomic developments nationally, within North America or globally, domestic and global commodity prices or current perceptions of the oil and gas market. 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. Factors that could affect the market price of our Common Shares that are unrelated to our performance include domestic and global commodity prices and market perceptions of the attractiveness of particular industries. The price at which our Common Shares will trade cannot be accurately predicted.

**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.**

The market price of the 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. While oil prices are set in a much broader global market, natural gas prices are largely dependent on North American economies. Additional factors include:

- 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;
- geo-political conditions;
- worldwide economic conditions including ongoing credit and liquidity concerns;
- 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
- government regulation.

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 2017 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 the recent changes in government at a federal level and, in the case of Alberta, at the provincial level and the resultant uncertainty surrounding regulatory, tax, royalty changes and environmental regulation that have been announced or may be implemented by the new governments.

In addition, the inability to get the necessary approvals to build pipelines 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.

**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 been attempting to negotiate covenant relief under our Credit Facility or Term Notes, but there is no certainty that our lenders will agree to provide covenant relief. In addition, if granted, covenant relief could result in higher interest charges, the pledging of our assets as security for all or a portion of our debt or the imposition of additional restrictive covenants. Failure to comply with our debt covenants or negotiate relief may result in our access to capital (including our ability to make borrowings under our Credit Facility) being restricted and our indebtedness under the Credit Facility and/or Term Notes becoming immediately due and payable, each of which may have a material adverse effect on our operations and financial condition.

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 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 and the 6.25% Series B Convertible Debentures on maturity. There is also a risk that the Credit Facility will not be renewed for the same amount or on the same terms. See "*Dividends - Revolving Credit Facility*".

**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.

**Political uncertainty has impacted 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 the recent U.S. presidential campaign a number of election promises were made and the new American administration has begun taking steps to implement certain of these promises. Included in the actions that the administration has discussed are the renegotiation of the terms of the North American Free Trade Agreement, withdrawal of the United States from the Trans-Pacific Partnership, imposition of a tax on the importation of goods into the United States, reduction of regulation and taxation in the United States, and introduction of laws to reduce immigration and restrict access into the United States for citizens of certain countries. It is presently unclear exactly what actions the new administration in the United States will implement, and if implemented, how these actions may impact Canada and in particular the oil and gas industry. Any actions taken by the new 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, the citizens of the United Kingdom recently voted to withdraw from the European Union and the Government of the United Kingdom has begun taken steps to implement such withdrawal.

**The amount of future dividends, if any, may vary.**

On January 20, 2016, as a result of volatile, uncertain and exceptionally low oil prices, we suspended our monthly dividend until further notice. The amount of future dividends paid by us, if any, will be subject to the discretion of our Board of Directors and may vary depending on a variety of factors, forecasts and conditions existing from time to time, including fluctuations in commodity prices, production levels, capital expenditure requirements, debt service requirements, operating costs, royalty burdens, foreign exchange rates and the satisfaction of the liquidity and solvency tests imposed by the ABCA for the declaration and payment of dividends. Depending on these and various other factors, many of which will be beyond our control, we may change our dividend policy from time to time and, as a result, any future dividends could be reduced or suspended entirely.

The future treatment of dividends for tax purposes will be subject to the nature and composition of dividends paid by us and potential legislative and regulatory changes. Dividends may be reduced during periods of lower funds from operations, which result from lower commodity prices and any decision by us to finance capital expenditures using funds from operations.

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

The loss of the services of key personnel may have a material adverse effect on our business, financial condition, results of operations and prospects. 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.

**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:

- 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 particular, 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. 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 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.

**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. A variety of new pipeline expansion projects to provide increased access to eastern Canadian and Gulf Coast refineries, as well as new off-shore markets, have been announced

and are in various stages of review and approval. There can be no assurance that such regulatory approvals will be secured on a timely basis or at all. The lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to produce and to market oil 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 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.

Following major accidents in Lac-Mégantic, 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.

**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, 2016 are estimated using forecast pricing escalating prices. These 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, 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.

**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/or 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. 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.

**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.

**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;
- 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.

**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 obligations. These programs generally 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 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 requirements. In addition, the liability management system 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. The recent Alberta Court of Queen's Bench decision, *Redwater Energy Corporation (Re)* 2016 ABQB 278, found an operational conflict between the *Bankruptcy and Insolvency Act* and the AER's abandonment and reclamation powers when the licensee is insolvent. The AER appealed this decision and issued interim rules to administer the liability management program until the Alberta Government can develop new regulatory measures to adequately address environmental liabilities. The decision from this appeal has not been released. There remains a great deal of uncertainty as to what new regulatory measures will be developed or what the impact of the court decision will have on other provinces. See "*Industry Conditions - Liability Management Rating Programs*".

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.

**Our exploration and production facilities and other operations and activities emit greenhouse gases which may require us to comply with greenhouse gas emissions legislation in Alberta and British Columbia or that may be enacted in other provinces.**

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 participant to the Copenhagen Agreement (a non-binding agreement created by the UNFCCC), the Government of Canada announced on January 29, 2010 that it would seek a 17 percent reduction in GHG emissions from 2005 levels by 2020; however, these GHG emission reduction targets were not binding. As a result of the UNFCCC adopting the Paris Agreement on December 12, 2015, which Canada ratified on October 3, 2016, the Government of Canada implemented a new GHG emission reduction target of a 30 percent reduction from 2005 levels by 2030. In addition, the Government of Canada announced it would implement a Canada wide price on carbon to further reduce its GHG emissions. In addition, on January 1, 2017 the CLA came into effect in the Province of Alberta introducing a carbon tax on almost all sources of GHG emissions at a rate of \$20 per tonne, increasing to \$30 per tonne in January 2018. Some of our significant facilities may ultimately be subject to future regional, provincial and/or federal climate change regulations to manage GHG emissions. The direct or indirect costs of compliance with these regulations may have a material adverse effect on our business, financial condition, results of operations and prospects. 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 not possible to predict the impact on us and our operations and financial condition. See "*Industry Conditions - Climate Change Regulation*".

**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 and in the marketing of oil and natural gas. Our competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than us. Our ability to increase our reserves in the future will depend not only on our ability to explore and develop our present properties, but also on our ability to select and acquire other suitable producing properties or prospects for exploratory drilling. Competitive factors in the distribution and marketing of oil and natural gas include price, methods, and reliability of delivery and storage.

**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.

**Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas, and technological advances in fuel economy and energy generation devices could reduce the demand for oil and liquid hydrocarbons.**

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.

**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.

**Our indebtedness may limit the amount of dividends that we are able to pay our Shareholders, and if we default on our debts, the net proceeds of any foreclosure sale would be allocated to the repayment of our lenders, note holders, Convertible Debenture holders and other creditors and only the remainder, if any, would be available for distribution to our Shareholders.**

We are indebted under our Credit Facility, the Convertible Debentures and the Term Notes. Certain covenants in the agreements with our lenders and with respect to the Term Notes and the Convertible Debentures may limit the amount of dividends paid to 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. 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, the Convertible Debentures and the 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.

**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. The federal government has signaled that it plans to review the National Energy Board approval process for large federally regulated projects. This may cause the timeframe for project approvals to increase for current and future applications.

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. 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 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.

**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 17.5 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 wilful 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.

**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 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.

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

World 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. Material increases in the value of the Canadian dollar relative to the United States dollar will negatively affect our production revenues. Future Canadian/United States exchange rates could, accordingly, affect the future value of our reserves as determined by independent evaluators.

Pengrowth has substantial exposure to the U.S. dollar. Any decrease in the value of the Canadian dollar relative to the U.S. dollar results in an increase in the Canadian dollar equivalent of Pengrowth's U.S. 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 U.S. dollar could cause Pengrowth to be in violation of its debt covenants resulting in Pengrowth being in default of its debt covenants.

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 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*".

**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.

**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.

**Future acquisitions may result in substantial future dilution of your Common Shares.**

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. Shareholders may also suffer dilution in connection with future issuances of Common Shares.

**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.

**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). Governments may regulate or intervene with respect to exploration and production activities, prices, taxes and royalties. Amendments to these controls and regulations may occur from time to time in response to economic or political conditions. On January 29, 2016, the Government of Alberta adopted a new royalty regime which took effect on January 1, 2017. Details of this new regime are scheduled to be finalized and released before March 31, 2016. See "*Industry Conditions - Royalties and Incentives*". 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 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 it may wish to undertake. In addition to regulatory requirements pertaining to the production, marketing and sale of oil and natural gas mentioned above, 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). See "*Industry Conditions*".

**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. Pengrowth utilizes hydraulic fracturing in a significant portion of the light oil wells it drills and completes. Pengrowth believes that the hydraulic fracturing that it conducts, given the depth and location of the wells and its 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, beginning June 1, 2013, has required operators to electronically submit reporting information for all hydraulic fracture stimulations performed after May 1, 2013.

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.

#### **Our waterflood activities may be restricted due to water restrictions.**

We undertake or intend to undertake certain waterflooding programs which involve the injection of water or other liquids into an oil reservoir to increase production from the reservoir and to decrease production declines. To undertake such waterflooding activities we require access to sufficient volumes of water, or other liquids, to pump into the reservoir to increase the pressure in the reservoir. There is no certainty that we will have access to the required volumes of water. In addition, in certain areas there may be restrictions on water use for activities such as waterflooding. If we are unable to access such water we may not be able to undertake waterflooding activities, which may reduce the amount of oil and natural gas that we are ultimately able to produce from our reservoirs. In addition, we may undertake certain waterflood programs that ultimately prove unsuccessful in increasing production from the reservoir and as a result have a negative impact on our results of operations.

**We may become involved in, named 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.**

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.

#### **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.

**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, may in the future be changed or interpreted in a manner that adversely affects us. Furthermore, 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.**

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. Also, 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 and cause operational difficulties. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and corresponding declines in the demand for our goods and services.

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

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.

**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.

**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. 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, 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 typical 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 may 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.

**If there are delays in our projects, this may delay our expected revenues from operations.**

We manage a variety of small and large projects in the conduct of our business. Project delays may delay expected revenues from operations. 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 capacity;
- the availability and proximity of pipeline capacity;
- the availability of storage 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 availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- changes in regulations;
- the availability and productivity of skilled labour; and
- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

Because of these factors, 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.

**We may be subject to growth-related risks including capacity constraints and pressure on our internal systems and controls.**

Our ability to manage growth effectively will require us to continue to implement and improve our operational and financial systems and to expand, train and manage our employee base. Our inability to deal with this growth may have a material adverse effect on our business, financial condition, results of operations and prospects.

**Potential conflicts of interest.**

Certain of our directors are also directors of other oil and gas companies and as such may, in certain circumstances, have a conflict of interest requiring them to 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.

**Asset Concentration**

With the sale of over \$1.3 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 failure to execute at Lindbergh or any of our remaining core properties could have a significant adverse effect on Pengrowth.

## Lindbergh Thermal Project Specific Risks

Our Lindbergh thermal project will require substantial capital investment over the coming years. In addition to the above, there are certain additional risk factors associated with the development of our Lindbergh thermal project. These include the following:

### *Early Stage of Development*

There is a risk that design and construction of the facilities and infrastructure to support our Lindbergh thermal project and any future commercial projects will not be completed on time, on budget or at all. Additionally, there is a risk that the Lindbergh thermal project and any future commercial projects may have delays, interruptions of operations or increased costs due to many factors, including, without limitation:

- inability to attract or retain sufficient numbers of qualified workers;
- breakdown or failure of equipment or processes;
- construction performance falling below expected levels of output or efficiency;
- design errors;
- non-performance by, or financial failure of, third-party contractors;
- labour disputes, disruptions or declines in productivity;
- increases in materials or labour costs;
- conditions imposed by regulatory approvals;
- delays induced by weather;
- disruption or delays in availability of pipelines and/or rail transportation services leading to volumes being shut-in or otherwise unable to reach markets;
- errors in construction;
- changes in project scope;
- unforeseen site surface or subsurface conditions;
- transportation or construction accidents;
- permit requirement violation;
- availability of water supplies;
- reservoir performance;
- energy supply disruption; and
- shortages of or delays in accessing drilling rigs and services.

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 receipt of all regulatory approvals and no material changes being made to the project or its scope.

Once expansion phases of the Lindbergh thermal project are sanctioned, 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 percent 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 cost to transport sales products and the cost to dispose of certain by-products;
- the cost of insurance; and
- catastrophic events such as fires, earthquakes, storms or explosions.

#### *Infrastructure for the Lindbergh Thermal Project*

We will depend, to a large extent, on third party designers, contractors and suppliers to design and construct the necessary facilities and infrastructure for any expansion phases of the Lindbergh thermal project. We also anticipate that we will 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 to complete the Lindbergh thermal project on a timely basis and on acceptable commercial terms would negatively impact our operation and financial results.

#### *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.

#### *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, scheme amendments, EPEA and *Water Act* (Alberta) approval amendments may be required. Pengrowth submitted a scheme amendment and an EPEA update in late February 2017, to increase the maximum oil rate after the Phase 2 development project to 40,000 bbl/day. The regulatory risk areas include but are not limited to; the regulators' ability to review the above 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. These issues or concerns may take a significant amount of time to meet the regulators' requirements to mitigate or eliminate 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.

## MARKET FOR SECURITIES

Our outstanding Common Shares are listed and posted for trading on the NYSE under the symbol "PGH" and on the TSX under the symbol "PGF". The following tables set forth certain trading information for the Common Shares in 2016 as reported by the TSX and the NYSE.

	TSX			NYSE		
	(\$) High	(\$) Low	Volume	(US\$) High	(US\$) Low	Volume
January	1.17	0.66	38,276,875	0.83	0.45	23,951,516
February	1.13	0.84	73,086,297	0.83	0.60	11,877,772
March	1.73	1.01	156,824,944	1.33	0.75	29,692,938
April	2.06	1.43	48,652,097	1.64	1.08	28,533,875
May	2.70	1.79	58,331,261	2.08	1.40	38,144,210
June	2.60	2.21	51,885,592	2.05	1.68	26,365,849
July	2.44	1.81	21,116,275	1.92	1.36	20,057,849
August	2.21	1.85	24,209,515	1.71	1.41	21,613,500
September	2.29	1.82	40,776,517	1.77	1.38	25,690,914
October	2.32	2.05	28,084,291	1.77	1.55	20,748,744
November	2.12	1.65	27,453,854	1.59	1.22	24,863,709
December	2.32	1.90	42,565,203	1.76	1.34	35,227,443

Our 6.25% Series B Convertible Debentures are listed and posted for trading on the TSX under the symbol "PGF.DB.B". The following table sets forth certain trading information for our 6.25% Series B Convertible Debentures in 2016 as reported by the TSX.

	6.25% SERIES B CONVERTIBLE DEBENTURES		
	(\$) High	(\$) Low	Volume
January	73.00	46.49	3,613,000
February	79.00	65.00	1,354,000
March	90.01	75.00	10,695,000
April	95.52	89.50	2,410,000
May	95.36	92.22	2,595,000
June	96.80	95.00	1,858,000
July	98.10	95.82	3,242,000
August	97.50	92.51	4,377,000
September	99.16	96.09	2,100,000
October	100.25	98.06	2,784,000
November	101.85	99.00	11,169,000
December	101.80	99.90	6,549,000

## 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 <sup>(1)(2)(3)(4)</sup> Alberta, Canada	Chairman and Director (Director since 2012)	President of Wylander Crude Corp. and Vice President, Corporate Development of Lakeview Energy Inc.
Derek W. Evans <sup>(6)</sup> Alberta, Canada	President, Chief Executive Officer and Director (Director since 2009) <sup>(5)</sup>	President and Chief Executive Officer of Pengrowth.
Wayne K. Foo <sup>(3)(4)</sup> Alberta, Canada	Director (Director since 2006) <sup>(5)</sup>	Chief Executive Officer of Parex Resources Inc. (energy company) since January 2015; prior thereto, President and Chief Executive Officer of Parex Resources Inc.
James D. McFarland <sup>(1)(2)</sup> Alberta, Canada	Director (Director since 2010) <sup>(5)</sup>	President, Chief Executive Officer and Director of Valeura Energy Inc.

Name and Jurisdiction of Residence	Position with Pengrowth	Principal Occupation
A. Terence Poole <sup>(1)</sup> Alberta, Canada	Director (Director since 2005) <sup>(5)</sup>	Business Consultant and Corporate Director.
Jamie C. Sokalsky <sup>(1)(4)</sup> Ontario, Canada	Director (Director since 2015)	Corporate Director since September 2014; prior thereto, Director, President and Chief Executive Officer of Barrick Gold Corporation from June 2012 to September 2014; prior thereto, Executive Vice President and Chief Financial Officer of Barrick Gold Corporation.
D. Michael G. Stewart <sup>(2)(3)</sup> Alberta, Canada	Director (Director since 2006) <sup>(5)</sup>	Corporate Director.
Douglas C. Bowles Alberta, Canada	Vice President and Controller	Vice President and Controller of Pengrowth.
Stephen J. De Maio Alberta, Canada	Senior Vice President, Thermal Operations	Senior Vice President, Thermal Operations of Pengrowth since May 2015; prior thereto Vice President In-Situ Development & Operations of Pengrowth.
David M. Granger Alberta, Canada	Vice President, Human Resources	Vice President, Human Resources of Pengrowth since April 2016; prior thereto, Principal, Ener-G HR Consulting Ltd. from April 2014 to March 2016; prior thereto, Vice President, Human Resources, Brewers Retail Inc.
Andrew D. Grasby Alberta, Canada	Senior Vice President, General Counsel & Corporate Secretary	Senior Vice President, General Counsel & Corporate Secretary of Pengrowth.
Randall S. Steele Alberta, Canada	Senior Vice President, Conventional Operations	Senior Vice President, Conventional Operations of Pengrowth since May 2015; prior thereto General Manager, Conventional Operations of Pengrowth since 2013; prior thereto General Manager, Swan Hills of Pengrowth.
Christopher G. Webster Alberta, Canada	Chief Financial Officer	Chief Financial Officer of Pengrowth.

**Notes:**

- (1) Member of the Audit and Risk Committee.
- (2) Member of Compensation Committee.
- (3) Member of Corporate Governance and Nominating Committee.
- (4) Member of Reserves, Health, Safety and Environment Committee.
- (5) Denotes year first appointed as a director of Pengrowth Corporation, a predecessor of ours. Each of the directors has agreed to serve as such until the next annual meeting of shareholders or until their successor is duly appointed.
- (6) Prior to January 1, 2016, Mr. Evans was a director of Endurance Energy Ltd. (a private oil and gas company) which filed for protection under the CCAA in May, 2016.

As at December 31, 2016, the foregoing directors and officers, as a group, beneficially owned, directly or indirectly, 2,837,024 Common Shares or approximately 0.52 percent of the issued and outstanding Common Shares and held rights and options to acquire a further 7,633,149 Common Shares (assuming 100 percent 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 above, 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, been 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
Kelvin B. Johnston	Yes	Yes	Mr. Johnston is an executive with more than 30 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. 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 Masters degree in Economics from the University of Calgary.
James D. McFarland	Yes	Yes	Mr. McFarland has more than 44 years' experience in the oil and gas industry, most recently as President, Chief Executive Officer, director and co-founder of Valeura Energy Inc., a TSX listed issuer. Prior thereto Mr. McFarland was President, Chief Executive Officer, director and a co-founder 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. 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.
A. Terence Poole	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 currently serves 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.
Jamie C. Sokalsky	Yes	Yes	Mr. Sokalsky currently serves as the Chairman of, and as the Chair of the audit committee of, Probe Metals Inc., a TSX-V listed company. He is currently a member of the audit committees of Agnico-Eagle Mines Limited and Royal Gold Inc., both TSX-listed companies. Pengrowth's Board has determined that, the fact that Mr. Sokalsky sits on the audit committees of a total of four public companies, does not impair his ability to effectively serve on Pengrowth's Audit and Risk Committee. He was formerly President and Chief Executive Officer of Barrick Gold Corporation (2012-2014) and prior to that, Executive Vice President and Chief Financial Officer of Barrick Gold Corporation (1999-2012). He is the former Chairman of Probe Mining Limited. He holds a Bachelor of Commerce degree (honours) from Lakehead University and is a Chartered Professional Accountant.

### Principal Accountant Fees and Services

The following table provides information about the aggregate fees billed to us for professional services rendered by KPMG LLP during fiscal 2016 and 2015:

	2016 (\$thousands)	2015 (\$thousands)
Audit Fees	884	962
Audit Related Fees	-	-
Tax Compliance and Preparation Services	8	13
Other Tax Services	13	26
All Other Fees	75	102
<b>Total</b>	<b>980</b>	<b>1,103</b>

#### **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 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 2016 and 2015 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 2016 and 2015 the services provided in this category relate to translation of financial statements, management 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 our 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

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 ten percent of our assets.

See "*Risk Factors - We may become involved in, named 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 U.S. 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 Accountants in Calgary, Alberta.

## MATERIAL CONTRACTS

The only material contracts entered into by us or Pengrowth Energy Trust 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 concerning the 2012 Senior Notes;
- (iii) the Note Purchase Agreement dated May 11, 2010 concerning the 2010 Senior Notes;
- (iv) the Note Purchase Agreement dated August 21, 2008 concerning the 2008 Senior Notes; and
- (v) the Note Purchase Agreement dated July 26, 2007 concerning the 2007 Senior Notes.

Copies of these contracts have been filed by us on SEDAR and are available through the SEDAR website at [www.sedar.com](http://www.sedar.com).

## CODE OF ETHICS

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 management, including its Chief Executive Officer, Chief Financial Officer and principal accounting officers. The Code of Ethics is available for viewing on our website [www.pengrowth.com](http://www.pengrowth.com) under the name "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 2100, 222 – 3<sup>rd</sup> Avenue S.W., Calgary, Alberta, Canada, T2P 0B4.

The Board adopted an amended and restated Code of Ethics on November 4, 2015. All Directors, officers, employees, consultants and contractors are required to accept the Code of Ethics annually.

During the year ended December 31, 2016, Pengrowth has not granted any waivers (including implicit waivers) from the Code of Ethics in respect of its Chief Executive Officer, Chief Financial Officer or its principal accounting officers.

## OFF-BALANCE SHEET ARRANGEMENTS

Pengrowth has no off-balance sheet arrangements.

## DISCLOSURE PURSUANT TO THE REQUIREMENTS OF THE NEW YORK STOCK EXCHANGE

As a Canadian reporting issuer with securities listed on the TSX and the NYSE, Pengrowth has in place a system of corporate governance practices which complies with Canadian securities laws and the TSX corporate governance guidelines as well as the corporate governance rules of the NYSE applicable to foreign private issuers. Pengrowth qualifies as a foreign private issuer under SEC rules and therefore only certain of the NYSE rules are applicable to Pengrowth. However, Pengrowth 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](http://www.pengrowth.com). The Board of Directors of the Corporation has also adopted Terms of Reference for each of an Audit and Risk Committee, a Corporate Governance and Nominating Committee, a Compensation Committee, and a Reserves, Health, Safety and Environment Committee, 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.

There is only one significant way in which Pengrowth's corporate governance practices differ from those required to be followed by domestic United States issuers under the NYSE Listed Company Manual. The NYSE Listed Company Manual requires shareholder approval of all equity compensation plans and any material revisions to such plans, regardless of whether the securities to be delivered under such plans are newly issued or purchased on the open market, subject to a few limited exceptions. In contrast, the TSX rules require shareholder approval of equity compensation plans only when such plans involve newly issued securities. Additionally, if an equity compensation plan provides a procedure for its amendment, the TSX rules require shareholder approval of amendments only where the amendment involves a reduction in the exercise price or an extension of the term of options held by insiders. Pengrowth follows the TSX rules regarding shareholder approval of equity compensation plans.

## ADDITIONAL INFORMATION

Additional information, including directors' and officers' remuneration, the principal holders of Common Shares and securities authorized for issuance under equity compensation plans, is contained in our Management Information Circular which relates to the Annual Meeting of Shareholders expected to be held on June 20, 2017. Additional financial information is contained in our comparative consolidated financial statements and associated management's discussion and analysis for the years ended December 31, 2016, 2015 and 2014.

Additional information relating to us may be found on SEDAR at [www.sedar.com](http://www.sedar.com) and on EDGAR at the SEC's website at [www.sec.gov](http://www.sec.gov).

For additional copies of the Annual Information Form and the materials listed in the preceding paragraphs please contact:

Investor Relations  
Pengrowth Energy Corporation  
Suite 2100, 222 – 3rd Avenue S.W.  
Calgary, Alberta T2P 0B4  
Telephone: (403) 233-0224  
Toll Free: (855) 336-8814  
Facsimile: (403) 265-6251  
Website: [www.pengrowth.com](http://www.pengrowth.com)  
E-mail: [investorrelations@pengrowth.com](mailto:investorrelations@pengrowth.com)

# 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, 2016. 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 the 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, unrisks and risks 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 percent, whereas the likelihood of a Contingent Resource achieving commerciality will be less than 100 percent.

### Summary of Gross Bitumen Reserves as of December 31, 2016 (Forecast Prices and Costs)

	Bitumen - Reserves Category		
	Total Proved	Total Proved Plus Probable	Total Proved Plus Probable Plus Possible
Gross Reserves (Mbbl)	146,265	317,905	413,227

### Summary of Gross Bitumen Contingent Resources as of December 31, 2016 (Forecast Prices and Costs)

Project Maturity Sub-Class <sup>(1)</sup>	Bitumen - Contingent Resource Category		
	Low Estimate	Best Estimate	High Estimate
Development Pending <sup>(2)</sup> - Unrisks (Mbbl)	16,690	35,716	59,945
Chance of Development	95%	95%	95%
Development Pending - Risks (Mbbl)	15,856	33,930	56,948
Development Unclarified <sup>(3)</sup> - Unrisks (Mbbl)	33,183	66,883	95,827
Chance of Development	58%	58%	58%
Development Unclarified - Risks (Mbbl)	19,113	38,525	55,196

**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, 2016  
(Forecast Prices and Costs)**

	Bitumen - Reserves Category		
	Total Proved	Total Proved Plus Probable	Total Proved Plus Probable Plus Possible
Net Reserves (Mbbbl)	118,077	250,299	314,843

**Summary of Net Bitumen Contingent Resources as of December 31, 2016  
(Forecast Prices and Costs)**

Project Maturity Sub-Class <sup>(1)</sup>	Bitumen - Contingent Resource Category		
	Low Estimate	Best Estimate	High Estimate
Development Pending <sup>(2)</sup> - Unrisked (Mbbbl)	13,734	28,626	49,056
Chance of Development	95%	95%	95%
Development Pending - Risked (Mbbbl)	13,047	27,195	46,604
Development Unclassified <sup>(3)</sup> - Unrisked (Mbbbl)	27,994	54,951	76,123
Chance of Development	58%	58%	58%
Development Unclassified - Risked (Mbbbl)	16,125	31,652	43,847

**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 unclassified, 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 Unclassified 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, 2016  
(Forecast Prices and Costs)**

Reserves Category	Before Income Taxes Discounted at (%/year) - \$MM				
	0%	5%	10%	15%	20%
Total Proved	4,298	2,129	1,289	900	688
Total Proved Plus Probable	9,052	4,698	2,721	1,723	1,170
Total Proved Plus Probable Plus Possible	13,569	6,168	3,328	2,046	1,382

**Summary of Bitumen Contingent Resources**  
**Net Present Value of Future Net Revenue as of December 31, 2016**  
**(Forecast Prices and Costs)**

Project Maturity Sub-Class			Before Income Taxes Discounted at (%/year) - \$MM				
			0%	5%	10%	15%	20%
Development Pending	Low Estimate	Unrisked	528	82	5	(6)	(7)
		Chance of Development	95%	95%	95%	95%	95%
		Risked	502	78	5	(6)	(6)
	Best Estimate	Unrisked	1,088	268	68	18	4
		Chance of Development	95%	95%	95%	95%	95%
		Risked	1,034	254	65	17	4
	High Estimate	Unrisked	1,322	680	350	180	90
		Chance of Development	95%	95%	95%	95%	95%
		Risked	1,256	646	332	171	85
Development Unclassified	Low Estimate	Unrisked	603	160	24	(17)	(27)
		Chance of Development	58%	58%	58%	58%	58%
		Risked	348	92	14	(10)	(16)
	Best Estimate	Unrisked	1,419	480	149	28	(15)
		Chance of Development	58%	58%	58%	58%	58%
		Risked	817	277	86	16	(9)
	High Estimate	Unrisked	2,621	820	268	80	11
		Chance of Development	58%	58%	58%	58%	58%
		Risked	1,510	472	155	46	6

**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. The gross risked Best Estimate and High Estimate development pending Contingent Resources have been reduced by approximately 29 MMbbl and 38 MMbbl, respectively, since December 31, 2015, due to reclassifying volumes estimated for infill drilling from Contingent Resources to reserves based on the Corporation's current development plan. 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 percent 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 unrisks capital cost to achieve commercial production is estimated to be \$474 million with initial capital expenditures forecast in 2023 and production to commence in 2025. 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 percent 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, 2016, 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 the 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, unrisks and risks 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 percent.

#### **Summary of Gross Bitumen Contingent Resources as of December 31, 2016 (Forecast Prices and Costs)**

Project Maturity Sub-Class <sup>(1)</sup>	Bitumen - Contingent Resource Category		
	Low Estimate	Best Estimate	High Estimate
Development Pending <sup>(2)</sup> - Unrisks (Mbbbl)	37,090	56,088	74,632
Chance of Development	90%	90%	90%
Development Pending - Risks (Mbbbl)	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, 2016 (Forecast Prices and Costs)**

Project Maturity Sub-Class <sup>(1)</sup>	Bitumen - Contingent Resource Category		
	Low Estimate	Best Estimate	High Estimate
Development Pending <sup>(2)</sup> - Unrisks (Mbbbl)	31,330	45,002	58,051
Chance of Development	90%	90%	90%
Development Pending - Risks (Mbbbl)	28,197	40,502	52,246

**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, 2016**  
**(Forecast Prices and Costs)**

Project Maturity Sub-Class			Before Income Taxes Discounted at (%/year) - \$MM				
			0%	5%	10%	15%	20%
Development Pending	Low Estimate	Unrisked	651	221	52	(19)	(51)
		Chance of Development	90%	90%	90%	90%	90%
		Risked	586	199	47	(17)	(46)
	Best Estimate	Unrisked	1,442	459	147	29	(22)
		Chance of Development	90%	90%	90%	90%	90%
		Risked	1,297	413	132	26	(19)
High Estimate	Unrisked	2,404	640	198	51	(9)	
	Chance of Development	90%	90%	90%	90%	90%	
	Risked	2,164	576	178	46	(8)	

**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 percent working interest in the Selina oil sands property. It is located approximately 30 kilometres 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 \$506 million with initial capital expenditures forecast in 2019 and production to commence in 2021. 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 percent 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 17 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, 2016, 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 the 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, unrisks and risks 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 percent, whereas the likelihood of a Contingent Resource achieving commerciality will be less than 100 percent.

**Summary of Gross Shale Gas Reserves as of December 31, 2016  
(Forecast Prices and Costs)**

	Shale Gas - Reserves Category		
	Total Proved	Total Proved Plus Probable	Total Proved Plus Probable Plus Possible
Gross Reserves (MMcf)	117,492	702,638	859,471

**Summary of Gross Shale Gas Contingent Resources as of December 31, 2016  
(Forecast Prices and Costs)**

Project Maturity Sub-Class <sup>(1)</sup>	Shale Gas - Contingent Resource Category		
	Low Estimate	Best Estimate	High Estimate
Development Pending <sup>(2)</sup> - Unrisks (MMcf)	616,910	913,621	1,115,628
Chance of Development	85%	85%	85%
Development Pending - Risks (MMcf)	524,374	776,578	948,284

**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, 2016  
(Forecast Prices and Costs)**

	Shale Gas - Reserves Category		
	Total Proved	Total Proved Plus Probable	Total Proved Plus Probable Plus Possible
Net Reserves (MMcf)	103,452	592,605	717,904

**Summary of Net Shale Gas Contingent Resources as of December 31, 2016  
(Forecast Prices and Costs)**

Project Maturity Sub-Class <sup>(1)</sup>	Shale Gas - Contingent Resource Category		
	Low Estimate	Best Estimate	High Estimate
Development Pending <sup>(2)</sup> - Unrisked (MMcf)	522,585	763,956	924,835
Chance of Development	85%	85%	85%
Development Pending - Risked (MMcf)	444,197	649,363	786,110

**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, 2016  
(Forecast Prices and Costs)**

Reserves Category	Before Income Taxes Discounted at (%/year) - \$MM				
	0%	5%	10%	15%	20%
Total Proved	193	103	59	34	20
Total Proved Plus Probable	1,614	667	321	166	86
Total Proved Plus Probable Plus Possible	2,204	836	397	209	114

**Summary of Shale Gas Contingent Resources  
Net Present Value of Future Net Revenue as of December 31, 2016  
(Forecast Prices and Costs)**

Project Maturity Sub-Class			Before Income Taxes Discounted at (%/year) - \$MM				
			0%	5%	10%	15%	20%
Development Pending	Low Estimate	Unrisked	1,245	432	160	57	15
		Chance of Development	85%	85%	85%	85%	85%
		Risked	1,058	367	136	49	13
	Best Estimate	Unrisked	2,231	716	259	92	24
		Chance of Development	85%	85%	85%	85%	85%
		Risked	1,897	609	220	79	20
	High Estimate	Unrisked	3,043	928	342	134	47
		Chance of Development	85%	85%	85%	85%	85%
		Risked	2,587	789	291	114	40

**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 last day of the reporting issuer's most recently completed financial year. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at last day of the reporting issuer's most recently completed financial year, 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 last day of the reporting issuer's most recently completed financial year, 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 last day of the reporting issuer's most recently completed financial year, 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 - \$MM)			
			Audited	Evaluated	Reviewed	Total
GLJ Petroleum Consultants	Dec. 31, 2016	Canada	-	4,535,273	-	<b>4,535,273</b>

6. The following tables set forth the risked volume and risked net present value of future net revenue (before deduction of income taxes) attributed to best estimate contingent resources, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, 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 Reserves (Country or Foreign Geographic Area)	Risked Volume (MMboe)	Risked Net Present Value of Future Net Revenue (before income taxes, 10% discount rate - \$MM)		
					Audited	Evaluated	Total
Development Pending Contingent Resources (2C)	GLJ Petroleum Consultants	Dec. 31, 2016	Canada	213.8	-	417,465	<b>417,465</b>

Classification	Independent Qualified Reserves Evaluator or Auditor	Effective Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Risked Volume (MMboe)
Development Unclassified Contingent Resources	GLJ Petroleum Consultants	Dec. 31, 2016	Canada	38.5

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 28, 2017.

(signed) "*Todd J. Ikeda*"

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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, 2016, 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, 2016, 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) "Derek W. Evans"  
Derek W. Evans  
President and Chief Executive Officer

(signed) "Randall S. Steele"  
Randall S. Steele  
Senior Vice President, Conventional Operations


(signed) "Wayne K. Foo"  
Wayne K. Foo  
Director

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

February 28, 2017

# APPENDIX D

## AUDIT AND RISK COMMITTEE TERMS OF REFERENCE

	<b>PENGROWTH ENERGY CORPORATION</b> Policies and Practices	Page 1 of 11
<b>TERMS OF REFERENCE</b> <b>AUDIT AND RISK COMMITTEE</b>		

### 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

#### REVIEW PROCEDURES

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, annual information form, 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 annual information form 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 annual information form 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 3, 2016.

## 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 the company).
  - (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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