PetrusResources

ANNUAL INFORMATION FORM

For the Year Ended December 31, 2016

Dated March 8, 2017

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DEFINITIONS

Capitalized terms in this annual information form ("**Annual Information Form**") have the meanings set forth below. Unless otherwise indicated, references herein to "$" or "dollars" are to Canadian dollars.

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

"**Arrangement**" means the arrangement involving Petrus, PhosCan, Old Petrus, Fox River and the shareholders thereof, completed pursuant to a plan of arrangement under section 193 of the ABCA.

"**Arrangement Agreement**" means the arrangement agreement dated November 29, 2015, as amended on December 15, 2015, among Petrus, Old Petrus, PhosCan and Fox River in respect of the Arrangement.

"**Arriva**" means Arriva Energy Inc., a corporation amalgamated with Old Petrus.

"**Arriva Acquisition**" means the acquisition by Old Petrus of all of the issued and outstanding Arriva Shares.

"**Arriva Shares**" means the common shares in the capital of Arriva.

"**Board of Directors**" or "**Board**" means our board of directors.

"**Common Shares**" means our common shares, as presently constituted.

"**Fox River**" means Fox River Resources Corporation.

"**GAAP**" means generally accepted accounting principles for publicly accountable enterprises in Canada which is currently in accordance with the International Financial Reporting Standards.

"**NGP**" means Wingren B.V., a company formed under the laws of the Netherlands and a subsidiary of NGP Natural Resources X, L.P.

"**Old Option Plan**" means the stock option plan of Old Petrus dated June 29, 2012.

"**Old Petrus**" means Petrus Resources Corp., which prior to filing articles of amendment on February 2, 2016, was named "Petrus Resources Ltd".

"**Old Petrus Options**" means options to purchase Old Petrus Shares, granted under the Old Option Plan.

"**Old Petrus Shares**" means the common shares of Old Petrus.

"**Old Petrus Warrants**" means the performance warrants of Old Petrus.

"**Option Plan**" means the share option plan of Petrus dated December 19, 2015.

"**Options**" means options to purchase Common Shares which may be granted pursuant to the Option Plan.

"**Petrus**", "**we**", "**us**", "**our**" or the "**Corporation**" means Petrus Resources Ltd., a corporation incorporated under the ABCA and includes its direct and indirect subsidiaries where the context requires.

"**PhosCan**" means Petrus Resources Inc., which prior to filing articles of amendment on February 2, 2016, was named "PhosCan Chemical Corp.".

"**PhosCan Shares**" means Class A common shares in the capital of PhosCan.

"**Preferred Shares**" means our first preferred shares issuable in series.

"**Private Placement**" means the private placement of an aggregate of 16,217,000 Subscription Receipts at a price of $1.85 per Subscription Receipt.

"**Ravenwood**" means Ravenwood Energy Corp., a corporation amalgamated with Old Petrus.

"**Ravenwood Acquisition**" means the acquisition by Old Petrus of all of the issued and outstanding Ravenwood Shares.

"**Ravenwood Shares**" means the common shares in the capital of Ravenwood.

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

"**Sproule**" means Sproule Associates Limited, independent petroleum consultants of Calgary, Alberta.

"**Sproule Report**" means the report prepared by Sproule dated March 8, 2017 and effective December 31, 2016 evaluating the crude oil, NGLs and natural gas and future net production revenues attributable to the properties of Petrus.

"**Subscription Receipts**" means the subscription receipts of Petrus, each of which entitled the holder thereof to receive 0.25 of one Common Share in accordance with the terms and conditions of subscription receipt agreements dated December 22, 2015, December 30, 2015 and January 13, 2015, respectively.

"**Tax Act**" means the *Income Tax Act*, R.S.C., 1985, c. 1, as amended.

"**TCPL**" means TransCanada Corporation.

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

<u>Selected Defined Oil and Natural Gas Terms</u>

Certain terms used in this Annual Information Form in describing reserves and other oil and natural gas information are defined below. Certain other terms and abbreviations used in this Annual Information Form, but not defined or described, are defined in NI 51-101, CSA 51-324 or the COGE Handbook (as each is defined below), as applicable and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101, CSA 51-324 or the COGE Handbook, as applicable.

"**COGE Handbook**" means the Canadian Oil and Gas Evaluation Handbook prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum.

"**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.

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

"**developed reserves**" are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (e.g., when compared to the cost of drilling a well) to put the reserves on production.

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

(a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines and power lines, to the extent necessary in developing the reserves;

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

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

(d) provide improved recovery systems.

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

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

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

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

(c) dry hole contributions and bottom hole contributions;

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

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

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

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

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

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

"**future net revenue**" means a forecast of revenue, estimated using forecast 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.

"**gross**" means:

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

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

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

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

"**light crude oil**" means crude oil with a relative density greater than 31.1 degrees API gravity.

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

"**natural gas liquids**" or "**NGLs**" 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**" means:

(a) in relation to an entity's interest in production and reserves, such entity's working interest (operating or non-operating) share after deduction of royalty obligations, plus the entity's royalty interests in production or reserves;

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

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

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

"**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.

"**property**" includes:

(a) fee ownership or a lease, concession, agreement, permit, licence or other interest representing the right to extract oil or gas subject to such terms as may be imposed by the conveyance of that interest;

(b) royalty interests, production payments payable in oil or gas, and other non-operating interests in properties operated by others; and

(c) an agreement with a foreign government or authority under which a reporting issuer participates in the operation of properties or otherwise serves as "producer" of the underlying reserves (in contrast to being an independent purchaser, broker, dealer or importer). A property does not include supply agreements, or contracts that represent a right to purchase, rather than extract, oil or gas.

"**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.

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

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

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

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

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

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

"**working interest**" means the percentage of undivided interest held by Petrus in the oil and/or natural gas or mineral lease granted by the mineral owner, Crown or freehold, which interest gives Petrus the right to "work" the property (lease) to explore for, develop, produce and market the leased substances.

ABBREVIATIONS AND CONVERSIONS

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

Oil and Natural Gas Liquids		Natural Gas	
Bbl	barrel	Mcf	thousand cubic feet
Bbls	barrels	MMcf	million cubic feet
Mbbls	thousand barrels	Mcf/d	thousand cubic feet per day
Bbls/d	barrels per day	MMcf/d	million cubic feet per day
NGLs	natural gas liquids	MMBtu	million British Thermal Units

Other Abbreviations:

AECO	a natural gas storage facility located at Suffield, Alberta
API	American Petroleum Institute
°API	an indication of the specific gravity of crude oil measured on the API gravity scale. Liquid petroleum with a specified gravity of 28° API or higher is generally referred to as light crude oil
BOE	barrel of oil equivalent on the basis of 1 BOE to 6 Mcf of natural gas
BOE/d	barrel of oil equivalent per day
MBOE	1,000 barrels of oil equivalent
MMBOE	1,000,000 barrels of oil equivalent
m3	cubic metres
$000s or M$	thousands of dollars
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

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

To Convert From	To	Multiply By
Mcf	Cubic metres	0.28174
Cubic metres	Cubic feet	35.494
Bbls	Cubic metres	0.159
Cubic metres	Bbls	6.293
Feet	Metres	0.305
Metres	Feet	3.281
Miles	Kilometres	1.609
Kilometres	Miles	0.621
Acres	Hectares	0.405
Hectares	Acres	2.50
Gigajoules	MMbtu	0.950
MMbtu	Gigajoules	1.0526

NOTE ON SHARE REFERENCES

On February 2, 2016, Petrus completed the Arrangement pursuant to which: (i) all of the issued and outstanding Old Petrus Shares were transferred to Petrus in exchange for one-quarter (0.25) of one Common Share per Old Petrus Share, which Common Shares were issued to the former holders of the Old Petrus Shares; (ii) holders of Subscription Receipts were issued one-quarter (0.25) of one Common Share for each Subscription Receipt held; and (iii) Petrus acquired all of the PhosCan Shares in exchange for 0.0452672 of one Common Share per PhosCan Share, which Common Shares were issued to the former holders of the PhosCan Shares. Unless otherwise indicated, references in this Annual Information Form to Old Petrus Shares are on a pre-Arrangement basis while references to Common Shares are on a post-Arrangement basis. Readers should multiply any referenced number of Old Petrus Shares and other rights to acquire Old Petrus Shares by 0.25 to arrive at the equivalent number of Common Shares or rights to acquire Common Shares post-Arrangement. Readers should multiply the issuance price of any Old

Petrus Shares or the exercise price of any rights to acquire Old Petrus Shares by 4 to arrive at the equivalent issuance price or exercise price for Common Shares or rights to acquire Common Shares post-Arrangement.

NOTES ON RESERVES DATA AND OTHER OIL AND NATURAL GAS INFORMATION

Caution Respecting Reserves Information

The determination of oil and natural gas reserves involves the preparation of estimates that have an inherent degree of associated uncertainty. Categories of proved and probable reserves have been established to reflect the level of these uncertainties and to provide an indication of the probability of recovery. The estimation and classification of reserves requires the application of professional judgment combined with geological and engineering knowledge to assess whether or not specific reserves classification criteria have been satisfied. Knowledge of concepts including uncertainty and risk, probability and statistics, and deterministic and probabilistic estimation methods is required to properly use and apply reserves definitions.

The recovery and reserve estimates of oil, NGLs and natural gas reserves provided herein are estimates only. Actual reserves may be greater than or less than the estimates provided herein. The estimated future net revenue from the production of our natural gas and petroleum reserves does not represent the fair market value of our reserves.

Caution Respecting BOE

In this Annual Information Form, the abbreviation BOE means barrel of oil equivalent on the basis of 1 Bbl to 6 Mcf of natural gas when converting natural gas to BOEs. **BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf to 1 Bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6 Mcf to 1 Bbl, utilizing a conversion ratio at 6 Mcf to 1 Bbl may be misleading as an indication of value.**

Drilling Locations

This Annual Information Form discloses drilling locations in three categories: (i) proved locations; (ii) probable locations; and (iii) unbooked locations. Proved locations and probable locations are derived from the Sproule Report and account for drilling locations that have associated proved and/or probable reserves, as applicable. Unbooked locations are internal estimates based on our prospective acreage and an assumption as to the number of wells that can be drilled per section based on industry practice and internal review. Unbooked locations do not have attributed reserves. Unbooked locations have been identified by management as an estimation of our multi-year drilling activities based on evaluation of applicable geologic, seismic, engineering, production and reserves information. There is no certainty that we will drill all unbooked drilling locations and if drilled there is no certainty that such locations will result in additional oil and natural gas reserves or production. The drilling locations on which we actually drill wells will ultimately depend upon the availability of capital, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, actual drilling results, additional reservoir information that is obtained and other factors. While certain of the unbooked drilling locations have been derisked by drilling existing wells in relative close proximity to such unbooked drilling locations, some of the other unbooked drilling locations are further away from existing wells where management has less information about the characteristics of the reservoir and therefore there is more uncertainty whether wells will be drilled in such locations and if drilled there is more uncertainty that such wells will result in additional oil and natural gas reserves or production.

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements contained in this Annual Information Form constitute forward-looking statements. These statements relate to future events or our future performance. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "seek", "anticipate", "plan", "continue", "estimate", "expect", "may", "will", "project", "predict", "potential", "targeting", "intend", "could", "might", "should", "believe" and similar expressions. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. We believe the expectations reflected in these forward-looking statements are reasonable but no assurance can be given that such expectations will prove to be correct and the forward-looking statements included in, or incorporated by reference into, this Annual Information Form should not be unduly relied upon. These forward-looking statements speak only as of the date of this Annual Information Form.

More particularly, this Annual Information Form contains forward-looking statements with respect to:

- Petrus' corporate strategy;
- planned capital expenditures and drilling activity in 2017;
- the processing and compression capability of the Ferrier gas plant;
- development plans for our proved and probable undeveloped reserves;
- plans for funding future development costs including the timing of future development projects;
- Petrus' dividend policy;
- anticipated timing of expenditures by us to satisfy our asset retirement obligations;
- anticipated impact of environmental laws and regulations on our business;
- anticipated land expiries;
- anticipated future abandonment and reclamation costs;
- expectations of the means of funding our ongoing environmental obligations;
- waterflood expansion opportunities;
- anticipated service cost declines;
- anticipated decline rates;
- drilling inventories; and
- the anticipated impact of the factors discussed under the heading "*Industry Conditions*" on the Corporation.

These forward-looking statements are based on certain key expectations and assumptions made by us, including, but not limited to:

- the performance characteristics of our assets;
- oil and natural gas production levels;
- the size of the oil and natural gas reserves;
- projections of market prices and costs;
- supply and demand for oil and natural gas;
- expectations regarding the ability to raise capital and to continually add to reserves through acquisitions and development;
- prevailing weather conditions, commodity prices and exchange rates;
- drilling plans;
- availability of labour, services and equipment;
- timing and amount of capital expenditures;
- future abandonment and reclamation costs;
- general economic and financial market conditions;
- tax horizons;
- government regulation in the areas of taxation, royalty rates and environmental protection;
- the success of our exploration and development activities;
- current commodity prices and royalty regimes;
- timing and amount of capital expenditures;
- future exchange rates;
- the impact of increasing competition;
- future operating costs;
- that the Corporation will have sufficient cash flow, debt or equity sources or other financial resources required to fund its capital and operating expenditures and requirements as needed;

- that the Corporation's conduct and results of operations will be consistent with its expectations;
- that the Corporation will have the ability to develop the Corporation's oil and natural gas properties in the manner currently contemplated;
- that current or, where applicable, proposed assumed industry conditions, laws and regulations will continue in effect or as anticipated as described herein; and
- that the estimates of the Corporation's reserves volumes and the assumptions related thereto (including commodity prices and development costs) are accurate in all material respects.

Statements relating to "reserves" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described can be profitably produced in the future.

The actual results could differ materially from those currently anticipated due to a number of factors and risks. These include, but are not limited to:

- volatility in market prices for oil and natural gas;
- volatility in exchange rates;
- liabilities inherent in oil and natural gas operations;
- uncertainties associated with estimating oil and natural gas reserves;
- inability to secure labour, services and equipment on a timely basis or favourable terms;
- competition for, among other things, acquisitions of reserves, undeveloped lands and skilled personnel;
- unfavourable weather conditions;
- incorrect assessments of the value of acquisitions and exploration and development programs;
- geological, technical, drilling, production and processing problems;
- availability and cost of capital;
- changes in legislation, including changes in tax laws, royalty rates and incentive programs relating to the oil and natural gas industry; and
- the other factors discussed under *Risk Factors*.

Although the forward-looking statements contained in this Annual Information Form are based upon assumptions which Petrus believes to be reasonable, Petrus cannot assure readers that actual results will be consistent with these forward-looking statements.

Petrus has included the above summary of assumptions and risks related to forward-looking information provided in this Annual Information Form in order to provide readers with a more complete perspective on the Corporation's current and future operations and such information may not be appropriate for other purposes. The Corporation's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements and, accordingly, no assurance can be given that any of the events anticipated by the forward-looking statements will transpire or occur, or if any of them do so, what benefits Petrus will derive therefrom.

Readers are cautioned that the foregoing lists of factors are not exhaustive. The forward-looking statements contained in this Annual Information Form are expressly qualified by this cautionary statement. We do not undertake any obligation to publicly update or revise any forward-looking statements other than as required under applicable securities laws.

NON-GAAP MEASURES

This Annual Information Form contains the term "operating netback". This indicator is not a recognized measure under GAAP and does not have a standardized meaning prescribed by GAAP.

We use operating netback to analyze our financial and operating performance and believe this measure provides useful supplemental information enabling us to analyze operating performance and provides an indication of the results generated by the Corporation's principal business activities. We feel this benchmark is a key measure of

Petrus' profitability and overall sustainability. Readers should be cautioned that this measure is not intended to represent operating profits and should not be construed as an alternative to cash flows from operating activities, net income (loss) or other measures of financial performance as determined in accordance with GAAP. Petrus' method of calculating this measure may differ from other companies, and accordingly, it may not be comparable to similar measures used by other companies.

Operating netback is a common non-GAAP financial measure used in the oil and gas industry which is a useful supplemental measure to evaluate the specific operating performance by product at the oil and gas lease level. The operating netback is calculated as realized price less royalties, operating and transportation expenses. It is presented on an absolute value and per unit of production basis.

CORPORATE STRUCTURE

General

Petrus was incorporated pursuant to the ABCA on November 25, 2015 as "Petrus Acquisition Corp.", for the sole purpose of participating in the Arrangement and the Private Placement. On February 2, 2016, pursuant to the Arrangement, Petrus filed articles of amendment to change its name to "Petrus Resources Ltd.". See "*Development of Our Business*".

Our head office is located at 2400, 240 – 4th Avenue S.W., Calgary, Alberta. Our registered office is located at 2400, 525 – 8th Avenue S.W., Calgary, Alberta. We are a reporting issuer in each of the provinces of British Columbia, Alberta and Ontario.

Commencing on February 8, 2016 the Common Shares were posted for trading on the TSX under the symbol "PRQ".

Inter-corporate Relationships

Petrus has two wholly owned subsidiaries, Old Petrus and PhosCan. Old Petrus is a corporation existing under the laws of Alberta. Phoscan is a corporation that was incorporated under the federal laws of Canada and, pursuant to the Arrangement, was continued to and currently exists under the laws of Alberta.

DEVELOPMENT OF OUR BUSINESS

The following is a summary of the developments of the business of Petrus over the last three completed financial years, including the business of Old Petrus during such period, as Petrus assumed and continued the business of Old Petrus following the completion of the Arrangement. Petrus did not assume or continue the business of Phoscan, as Phoscan spun-off all its assets and liabilities to Fox River, a company incorporated for the sole purpose of assuming the liabilities and non-retained assets of PhosCan upon completion of the Arrangement. See "*Note on Share References*" and "*Description of Our Business – Reorganizations*".

2014

Overview of Capital Expenditure Program

During the financial year ended December 31, 2014, Old Petrus executed a $115.2 million capital program and drilled or participated in 43 gross (29.3 net) wells. Average production for the year was 6,032 BOE/d (46% oil and liquids).

General Business Developments

On February 28, 2014, Old Petrus completed the acquisition of certain oil and natural gas assets from its working interest partner in the Foothills area (the "**2014 Foothills Acquisition**"). The 2014 Foothills Acquisition was completed for total cash consideration of $19.1 million, before closing adjustments and related costs.

On February 28, 2014, in conjunction with the 2014 Foothills Acquisition, the Old Petrus revolving credit facility was increased from $60 million to $90 million and was then comprised of an $80 million revolving credit facility and a $10 million development line (the "**Old Petrus Facility**").

In June 2014, Old Petrus completed: (i) a brokered private placement of 9.2 million Old Petrus Shares (approximately 2.3 million Common Shares) at an issue price of $3.25 per Old Petrus Share (equivalent to $13.00 per Common Share); and (ii) a non-brokered private placement of 6.0 million Old Petrus Shares (approximately 1.5 million Common Shares) at an issue price of $3.25 per Old Petrus Share (equivalent to $13.00 per Common Share) and 115,000 Old Petrus Shares (approximately 28,750 Common Shares) issued on a "flow-through" basis pursuant to the provisions of the Tax Act at an issue price of $3.90 per Old Petrus Share (equivalent to $15.60 per Common Share), for aggregate gross proceeds of approximately $50 million. The net proceeds from this private placement were used to repay outstanding debt under the Old Petrus Facility.

On July 31, 2014, Old Petrus entered into another credit agreement, pursuant to which a syndicate of lenders agreed to provide an operating facility (the "**Operating Facility**") and a revolving syndicated credit facility (the "**Syndicated Facility**" and, together with the Operating Facility, the "**Credit Facilities**")**.** At that time, the Syndicated Facility was an $80 million committed secured, extendible, 364-day revolving plus one year term-out facility and the Operating Facility was a $20 million committed secured, extendible, 364-day revolving plus one year term out facility.

On August 22, 2014, Petrus entered into a commitment letter and term sheet with a third-party lender to provide for a committed second lien term loan in the amount of $90 million (the "**Petrus Term Loan**"). The Petrus Term Loan was made available concurrently with the completion of the Ravenwood Acquisition and was used to fund a portion of the purchase price therefor.

On September 3, 2014, Old Petrus completed the acquisition, from an industry partner, of petroleum and natural gas assets in the Ferrier/Strachan area of Alberta for cash consideration of $14.8 million (the "**Ferrier Asset Acquisition**"). The assets consisted of 10,000 net acres of undeveloped land and production, at the time of the acquisition, of approximately 160 BOE/d.

On September 8, 2014, Old Petrus completed the acquisition of Arriva, a private junior energy corporation that was engaged in the exploration, development, production and acquisition of oil and natural gas reserves in the Ferrier/Strachan area of Alberta, pursuant to which Old Petrus, through an all-cash offer, acquired all of the issued and outstanding Arriva Shares at a purchase price of $2.05 per Arriva Share, including any Arriva Shares issued pursuant to certain outstanding options, by way of take-over bid. See "*Principal Properties – Ferrier/Strachan Area - West Central Alberta*".

Concurrent with the completion of the Arriva Acquisition, the Syndicated Facility increased by $40 million to $120 million, while the Operating Facility remained unchanged.

On October 8, 2014, Old Petrus completed the acquisition of Ravenwood, a private junior energy corporation engaged in the exploration, development, production and acquisition of oil and natural gas reserves in the Greater Pembina area of central Alberta, pursuant to which Old Petrus, through an all-cash offer, acquired all of the issued and outstanding Ravenwood Shares at a purchase price of $3.08 per Ravenwood Share, including any Ravenwood Shares issued pursuant to certain outstanding options, by way of a take-over bid. See "*Principal Properties – Thorsby/Pembina Area - Central Alberta*".

Concurrent with the completion of the Ravenwood Acquisition, the Credit Facilities were amended and restated. The Syndicated Facility increased by an additional $60 million to $180 million, while the Operating Facility remained unchanged at $20 million.

On October 8, 2014, Old Petrus amalgamated with Arriva and Ravenwood.

In September and October 2014, Old Petrus completed in multiple tranches: (i) a brokered private placement of 12.5 million Old Petrus Shares (approximately 3.1 million Common Shares) at an issue price of $4.00 per Old Petrus

Share (equivalent to $16.00 per Common Share); and (ii) a non-brokered private placement of 26.1 million Old Petrus Shares (approximately 6.5 million Common Shares) at an issue price of $4.00 per Old Petrus Share (equivalent to $16.00 per Common Share) and 200,000 Old Petrus Shares (50,000 Common Shares) issued on a "flow-through" basis pursuant to the provisions of the Tax Act at an issue price of $4.80 per Old Petrus Share (equivalent to $19.20 per Common Share) for aggregate gross proceeds of approximately $155.5 million.

2015

Overview of Capital Expenditure Program

During the financial year ended December 31, 2015, Old Petrus invested $55.4 million to drill 5 gross (4.7 net) wells and for construction costs related to an operated gas plant in the Ferrier/Strachan area of Alberta. The 25 MMcf per day plant is connected directly to a TCPL sales pipeline and is capable of natural gas liquids refrigeration and liquids recovery in order to reduce reliance on third parties for processing. Average production for the year ended December 31, 2015 was 8,762 BOE/d (39% oil and natural gas liquids).

General Business Developments

On May 31, 2015, Old Petrus amended and restated the terms of the Credit Facilities. The Syndicated Facility was decreased from its then current amount to $160 million, while the Operating Facility remained unchanged at $20 million. The Credit Facilities also included a $20 million non-borrowing base facility, which required prior written consent of the lenders to be drawn (the "**Non-Borrowing Base Facility**").

On November 19, 2015, the Credit Facilities were amended and restated in conjunction with the semi-annual borrowing base review. The Syndicated Facility was decreased from its then current amount to $140 million, while the Operating Facility remained unchanged at $20 million. The Non-Borrowing Base Facility of $20 million was terminated to reduce interest fees.

On November 29, 2015, Petrus entered into the Arrangement Agreement. In connection with the Arrangement, on November 29, 2015, Petrus and Old Petrus entered into a bought deal letter agreement with certain underwriters providing for the Private Placement. The Private Placement was completed on January 14, 2016. The Arrangement closed on February 2, 2016. Pursuant to the Arrangement, among other things: (i) PhosCan spun-off all of its assets, including its mineral leases, other than approximately $45.4 million in cash (after taking into consideration adjustments for the shareholders of PhosCan who exercised dissent rights), and all of its liabilities to Fox River, a company incorporated for the sole purpose of assuming the liabilities and non-retained assets of PhosCan upon completion of the Arrangement; (ii) all of the issued and outstanding Old Petrus Shares were transferred to Petrus in exchange for one-quarter (0.25) of one Common Share per Old Petrus Share, which Common Shares were issued to the former holders of the Old Petrus Shares; (iii) holders of Subscription Receipts were issued one-quarter (0.25) of one Common Share for each Subscription Receipt held; and (iv) Petrus acquired all of the PhosCan Shares in exchange for 0.0452672 of one Common Share per PhosCan Share, which Common Shares were issued to the former holders of the PhosCan Shares.

2016

Overview of Capital Expenditure Program

During the financial year ended December 31, 2016, Petrus invested $28.2 million to drill 11 gross (7.3 net) wells and for construction costs related to facilities and pipeline infrastructure in the Ferrier/Strachan area of Alberta. Average production for the year ended December 31, 2016 was 8,236 BOE/d (31% oil and natural gas liquids).

General Business Developments

On February 1, 2016, Petrus amended the Credit Facilities to account for the change caused by the Arrangement to Petrus' corporate and share structure. The Syndicated Facility remained at its then current amount of $140 million, while the Operating Facility remained unchanged at $20 million (the "**Petrus Credit Facilities**").

On February 8, 2016, the Common Shares were listed on the TSX under the symbol "PRQ".

On February 16, 2016, the Board of Directors approved an interim budget for the first half of 2016 in the amount of $11 million. The program included the drilling of up to 3 gross (2.5 net) Cardium horizontal wells in the Ferrier/Strachan area. The budget also included funds for facilities and gathering system acquisitions and enhancements to further improve operational efficiencies and lower operating expenses.

On March 22, 2016, Petrus made a $40 million repayment on the Petrus Term Loan, using proceeds from the Arrangement and the Private Placement. The maturity date of the Petrus Term Loan was extended to October 1, 2017. The Petrus Credit Facilities were unchanged other than an amendment to require lender consent for advances in excess of $120 million under the Petrus Credit Facilities.

On July 8, 2016, Petrus sold its oil and natural gas interests in the Peace River area of Alberta to Rising Star Resources Ltd. ("**Rising Star**"), a private company, for total consideration of $30.0 million subject to customary closing adjustments (the "**Disposition**"). The consideration was comprised of $29.0 million in cash and 1.0 million shares of Rising Star at a deemed value of $1.00 per share. The Disposition closed on July 8, 2016 and had an effective date of April 1, 2016. Petrus disposed of the shares of Rising Star on December 16, 2016 at a price of $1.07 per share for gross proceeds of approximately $1.07 million.

The cash proceeds from the Disposition were used to reduce the amount owing under the Syndicated Facility to approximately $84 million and the amount owing under the Petrus Term Loan to $42 million. The borrowing capacity under the Syndicated Facility was reduced as a result of the Disposition, from $100 million to $86 million. The Operating Facility remained unchanged at $20 million for total Petrus Credit Facilities of $106 million.

On November 7, 2016, Mr. Kevin Adair resigned from his position as President and Chief Executive Officer, and as a director of Petrus. Mr. Neil Korchinski, previously Vice President Engineering and Chief Operating Officer, was promoted to the role of President and Chief Executive Officer and joined the Board of Directors.

Recent Developments

On January 23, 2017, Petrus appointed three new officers: Mr. Brett Booth was appointed Vice President Land, Mr. Ross Keilly was appointed Vice President Exploration and Mr. Marcus Schlegel was appointed Vice President Engineering.

On January 24, 2017, Petrus entered into an agreement to extend the Petrus Term Loan by two years to October 8, 2019. Concurrent with the extension, Petrus reduced the amount outstanding under the Petrus Term Loan by $7 million to $35 million.

On February 28, 2017, Petrus completed the acquisition, from a private company of certain oil and natural gas interests in the Ferrier area of Alberta (the "**2017 Ferrier Acquisition**") for cash consideration of $8.9 million net of closing adjustments.

Also on February 28, 2017, the Corporation closed a private placement of Common Shares at a price of $2.53 per Common Share for aggregate gross proceeds of $10.3 million. A portion of the net proceeds of the Private Placement were used to fund the 2017 Ferrier Acquisition and Petrus expects the remainder will be used to fund the Company's 2017 capital program.

Significant Acquisitions

Petrus did not complete any significant acquisitions during its most recently completed financial year for which disclosure is required under Part 8 of National Instrument 51-102 – *Continuous Disclosure Obligations*.

DESCRIPTION OF OUR BUSINESS

Corporate Strategy

Petrus is a Canadian oil and natural gas company focused on property exploitation and strategic acquisitions in Alberta. Since inception in 2011, through a combination of acquisitions and drilling in its core areas, production has grown to an annual average of 8,236 BOE/d as of December 31, 2016.

We have completed three material acquisitions to establish our current core areas of operation in all season access lands with significant infrastructure in the Ferrier/Strachan, Foothills and Thorsby/Pembina areas of Alberta. Management believes these acquisitions provide a sustainable platform of low decline oil and natural gas production, along with a multi-year inventory of drilling locations that includes certain locations which management believes are economic in today's commodity price environment. See "*Principal Properties*".

The Board of Directors may, in its discretion, approve asset or corporate acquisitions or investments based upon its consideration of the qualitative aspects of the subject properties, including risk profile, technical upside, reserve life, strategic importance and asset quality. See "*Industry Conditions*" and "*Risk Factors – Failure to Realize Anticipated Benefits of Acquisitions and Dispositions*".

Specialized Skill and Knowledge

Petrus employs individuals with various professional skills in the course of pursuing its business plan. These professional skills include, but are not limited to, engineering, financial, geology, geophysics and business skills, which are widely available in the industry. Drawing on significant experience in the oil and natural gas business, Petrus believes its management team has a demonstrated track record of bringing together all of the key components to a successful exploration and production company: strong technical skills; expertise in planning and financial controls; ability to execute on business development opportunities; capital markets expertise; and an entrepreneurial spirit that allows Petrus to effectively identify, evaluate and execute on its business plan.

Reorganizations

On February 2, 2016, Petrus completed the Arrangement, whereby, among other things: (i) PhosCan spun-off all of its assets, including its mineral leases, other than approximately $45.4 million in cash (after taking into consideration adjustments for the shareholders of PhosCan that exercised dissent rights), and all of its liabilities to Fox River (ii) all of the issued and outstanding Old Petrus Shares were transferred to Petrus in exchange for one-quarter (0.25) of one Common Share per Old Petrus Share, which Common Shares were issued to the former holders of the Old Petrus Shares; (iii) pursuant to the Private Placement, holders of Subscription Receipts were issued one-quarter (0.25) of one Common Share for each Subscription Receipt held; and (iv) Petrus acquired all of the PhosCan Shares in exchange for 0.0452672 of one Common Share per PhosCan Share, which Common Shares were issued to the former holders of the PhosCan Shares.

Competitive Conditions

The oil and natural gas industry is competitive in all its phases. We compete with numerous other participants in the acquisition, exploration and development of oil and natural gas assets and in the marketing of oil and natural gas. Our competitors include resource companies which may have greater financial resources, staff and facilities than us. We believe that our competitive position is, on the whole, equivalent to that of other oil and natural gas producers of similar size and at a similar stage of development.

Over the past number of years, there has been a sustained high demand for the services necessary to drill and complete the types of horizontal wells that form a substantial portion of our exploration and development activities. While the current economic and commodity price environment have reduced this demand, we remain in competition to secure such services on a timely and cost effective basis. See "*Industry Conditions*" and "*Risk Factors – Competition*".

Environmental Policies

We promote safety and environmental awareness and protection through the implementation and communication of our environmental management and employee occupational health and safety programs, policies and procedures. Committee structures are established in our operations which are designed to allow for employee participation and development of policies and programs which provide employees with job orientation, training, instruction and supervision to assist them in conducting their activities in an environmentally responsible and safe manner.

We have developed emergency response teams and preparedness plans in conjunction with local authorities, emergency services and the communities in which we operate in order to effectively respond to an environmental incident should it arise. Environmental assessments are undertaken for new projects, or when acquiring new properties or facilities, in order to identify, assess and minimize environmental risks and operational exposures. We periodically conduct reviews of operations to confirm compliance with internal standards and to stimulate improvement in practices where needed. Documentation is maintained to support internal accountability to assist in achieving the objectives of the described policies and programs.

We also face environmental, health and safety risks in the normal course of our operations due to the handling and storage of hazardous substances. Our environmental and occupational health and safety management systems are designed to manage such risks and allow action to be taken to mitigate the extent of any environmental, health or safety impacts from such operations. A key aspect of these systems is the performance of annual environmental and occupational health and safety reviews. See "*Industry Conditions*" and "*Risk Factors - Environmental".*

Seasonal Factors

The exploration for and development of oil and natural gas reserves is dependent on access to areas where operations are to be conducted. Seasonal weather variations, including freeze-up and break-up, affect access in certain circumstances. Unexpected adverse weather conditions, such as flooding or prolonged break-up, can have a significant negative impact on our operations and costs. See "*Industry Conditions*" and "*Risk Factors - Availability of Drilling Equipment and Access*".

Personnel

As at December 31, 2016, Petrus had 22 full-time employees and 20 consultants under contract.

PRINCIPAL PROPERTIES

Ferrier/Strachan Area – West Central Alberta

The Ferrier/Strachan area is located in west central Alberta near the town of Rocky Mountain House, Alberta. Petrus currently holds an average 55% working interest in 69,277 gross (38,166 net) acres of land in the Ferrier/Strachan area, of which 44,192 gross (27,342 net) acres are undeveloped and 25,085 gross (10,824 net) acres are developed. Petrus acquired the assets in the Ferrier/Strachan area through the Arriva Acquisition, the Ferrier Asset Acquisition, farm-in agreements with joint venture partners and other minor acquisitions. Exploration, development and production activities in the Ferrier/Strachan area are primarily directed toward natural gas and natural gas liquids in the Cardium formation.

Sproule assigned approximately 18,964 MBOE of proved reserves and 26,807 MBOE of proved plus probable reserves to the Ferrier/Strachan area in the Sproule Report. During the year ended December 31, 2016, the Ferrier/Strachan area provided Petrus with average production of approximately 3,696 BOE/d (including 1,038 Bbls/d of oil and natural gas liquids and 15,949 Mcf/d of natural gas) from 89 gross (40.6 net) producing wells. As at December 31, 2016, we operated approximately 90% of our production in the Ferrier/Strachan area. The majority of Petrus' Ferrier/Strachan production is pipeline connected to its owned and operated gas plant. Natural gas and natural gas liquids are either processed at a third party gas plant, or at Petrus' processing facility and gas plant, both of which are pipeline connected to a sales point.

Petrus invested approximately $25.0 million in the Ferrier/Strachan area in the year ended December 31, 2016. 11 gross (7.3 net) wells were drilled in the year ended December 31, 2016 and 8 gross (6.1 net) were on production by year-end. The majority of the capital invested at Ferrier/Strachan during 2016 was directed towards drilling, completion, tie-in and equipping of the new wells.

On February 28, 2017, Petrus acquired approximately 40 BOE/d of production, a 100% working interest in a drilled and completed Cardium horizontal well and a 100% working interest in approximately 3,360 net acres of undeveloped Cardium land in the Ferrier/Strachan area pursuant to the 2017 Ferrier Acquisition.

Foothills Area – West Central Alberta

The Foothills area is located in a trend from approximately 75 km northwest of Rocky Mountain House, Alberta to approximately 75 km northwest of Hinton, Alberta. Petrus currently holds an average 58% working interest in 111,260 gross (64,020 net) acres of land in the Foothills area, of which 87,740 gross (55,570 net) acres are undeveloped and 23,520 gross (8,450 net) acres are developed. Petrus has wells producing from the Cardium, Charlie Lake, Montney, Leduc, Dunvegan and Notikewin formations, as well as other formations. The properties located in the northern section of the Foothills area feature a predominantly mature production base with a stable production decline and reserve bookings. The properties located in the southern Foothills area include Brown Creek and Cordel/Stolberg, where we have focused the majority of our Foothills development to date. Petrus acquired its Foothills assets through a combination of asset acquisitions and farm-ins. Petrus currently operates 36% of its Foothills production and has a working interest in a variety of compressor stations, gas plants and pipeline infrastructure.

Sproule assigned approximately 5,525 MBOE of proved reserves and 8,196 MBOE of proved plus probable reserves to the Foothills area in the Sproule Report. During the year ended December 31, 2016, the Foothills area provided Petrus with average production of approximately 1,682 BOE/d (including 404 Bbls/d of oil and natural gas liquids and 7,670 Mcf/d of natural gas) from 78 gross (28.4 net) producing wells. As at December 31, 2016, we operated approximately 36% of our production in the Foothills area. Substantially all of our Foothills natural gas production is pipeline connected. Natural gas and natural gas liquids are processed at jointly owned and third party gas plants and then go directly to sales. The majority of our Foothills light oil production is pipeline connected to satellite oil batteries; clean oil is trucked directly to sale terminals once processed at the respective oil battery.

Petrus did not invest significant capital in this area in 2016; however, Petrus has plans for additional development opportunities in the area in the event that commodity prices improve.

Thorsby/Pembina Area – Central Alberta

The Thorsby/Pembina area of central Alberta is located approximately 70 kilometers southwest of Edmonton, Alberta. Petrus currently holds an average 61% working interest in 132,985 gross (80,663 net) acres of land in the Thorsby/Pembina area, of which 51,010 gross (29,703 net) acres are undeveloped and 81,975 gross (50,960 net) acres are developed. Petrus acquired its assets in the central Alberta area through the Ravenwood Acquisition. Our exploration, development and production activities in the Thorsby/Pembina area are primarily directed towards light oil in the Glauconite formation.

Sproule assigned approximately 6,614 MBOE of proved reserves and 11,007 MBOE of proved plus probable reserves in central Alberta in the Sproule Report. The majority of the reserves are attributed to the Thorsby area (6,374 MBOE of proved reserves and 10,581 MBOE of proved plus probable reserves). The remaining reserves are attributed to non-core, minor properties in the greater central Alberta area.

During the year ended December 31, 2016, Petrus had average production of approximately 2,312 BOE/d (including 824 Bbls/d of oil and liquids and 8,929 Mcf/d of natural gas) from 145 gross (110.2 net) producing wells in the central Alberta area. As at December 31, 2016, we operated approximately 96% of the production in the Thorsby/Pembina area. Substantially all of our production in the area is pipeline connected to owned and operated oil batteries and gas plants. Clean oil and natural gas is transferred directly to sales pipelines once processed at an oil battery.

Petrus is evaluating waterflood expansion opportunities to optimize its assets in the central Alberta area. Petrus did not invest significant capital in this area in 2016; however, Petrus has plans for additional development opportunities in the area in the event that commodity prices improve.

STATEMENT OF RESERVES DATA

The report of Sproule in Form 51-101F2 and the report of management and directors on oil and natural gas disclosure in Form 51-101F3 and the report on reserves data by are attached as Schedules "B" and "C" to this Annual Information Form, respectively.

Disclosure of Reserves Data

The statement of reserves data and other oil and natural gas information set forth below (the "**Reserves Data**") is based upon an evaluation by Sproule with an effective date of December 31, 2016, contained in the Sproule Report, which has a preparation date of March 8, 2017. The Sproule Report evaluated, as at December 31, 2016, the crude oil, NGLs and natural gas reserves of Petrus. The Reserves Data summarizes Petrus' crude oil, NGLs and natural gas reserves and the net present values of future net revenue for these reserves using forecast prices and costs.

The Sproule Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101 and the COGE Handbook. Additional information not required by NI 51-101 has been presented to provide continuity and additional information which the Corporation believes is important to readers of this Annual Information Form. Sproule was engaged to provide evaluations of proved and proved plus probable reserves and no attempt was made to evaluate possible reserves.

The Sproule Report is based on certain factual data supplied by us and Sproule's opinion of reasonable practice in the industry. The extent and character of ownership and all factual data pertaining to petroleum properties and contracts (except for certain information residing in the public domain) were supplied by us to Sproule. Sproule accepted this data as presented and neither title searches nor field inspections were conducted.

The net present value of future net revenue attributable to reserves is stated without provision for interest costs and general and administrative costs, but after providing for estimated royalties, production costs, development costs, other income, future capital expenditures and well abandonment and reclamation costs.

Petrus determined the future net revenue and present value of future net revenue after income tax expenses by utilizing Sproule's before income tax future net revenue and our estimate of income tax. Our estimates of the after income tax value of future net revenue have been prepared based on before income tax reserves information and include assumptions and estimates of our tax pools and the sequences of claims and rates of claim thereon. The values shown may not be representative of future income tax obligations, applicable tax horizon or after tax valuation. The after tax net present value of our oil and natural gas properties reflects the tax burden of our properties on a stand-alone basis. It does not provide an estimate of the value of Petrus as a business entity, which may be significantly different. Our financial statements for the year ended December 31, 2016 should be consulted for additional information regarding our taxes.

All of Petrus' consolidated reserves are in Canada and, specifically, in the Province of Alberta.

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

It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to reserves estimated by Sproule represent the fair market value of those reserves. Other assumptions and qualifications relating to costs, prices for future production and other matters are summarized herein. The recovery and reserve estimates of crude oil, NGLs and natural gas reserves provided herein are estimates only. Actual reserves may be greater than or less than the estimates provided herein.

The information relating to the Corporation's consolidated crude oil, NGLs and natural gas reserves contains forward-looking statements relating to future net revenues, forecast capital expenditures, future development plans, timing and costs related thereto, forecast operating costs, anticipated production and abandonment costs. See "*Special Note Regarding Forward-Looking Statements*", "*Industry Conditions*" and "*Risk Factors*".

In certain of the tables set forth below, the columns may not add due to rounding.

Reserves Data (Forecast Prices and Costs)

SUMMARY OF OIL AND NATURAL GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF DECEMBER 31, 2016
FORECAST PRICES AND COSTS

	RESERVES									
	GROSS RESERVES					NET RESERVES				
RESERVE CATEGORY	Light and Medium Crude Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Conventional Natural Gas (MMcf)	Coalbed Methane Gas (MMcf)	Total BOE (MBOE)	Light and Medium Crude Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Conventional Natural Gas (MMcf)	Coalbed Methane Gas (MMcf)	Total BOE (MBOE)
PROVED:										
Developed Producing	1,888.7	2,249.7	58,066	25	13,820.4	1,614.0	1,647.8	49,257	22	11,475.0
Developed Non-Producing	80.6	242.4	15,510	—	2,908.2	74.2	198.4	12,999	—	2,439.1
Undeveloped	1,948.3	2,770.1	58,058	—	14,394.8	1,698.0	2,393.7	50,966	—	12,586.1
TOTAL PROVED	3,917.6	5,262.2	131,635	25	31,123.3	3,386.2	4,239.9	113,223	22	26,500.3
PROBABLE	2,966.1	2,317.0	57,720	2	14,903.4	2,500.5	1,822.6	49,446	1	12,564.3
TOTAL PROVED PLUS PROBABLE	6,883.7	7,579.2	189,356	27	46,026.7	5,886.7	6,062.5	162,668	24	39,064.6

	NET PRESENT VALUES OF FUTURE NET REVENUE BEFORE INCOME TAX EXPENSES DISCOUNTED AT (%/year)					
RESERVES CATEGORY	0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)	Unit Value Before Income Tax Discounted at 10% per Year[(1)] ($/BOE)
PROVED:						
Developed Producing	259,804	210,611	180,316	158,274	141,401	15.71
Developed Non-Producing	39,223	29,030	23,210	19,327	16,516	9.52
Undeveloped	190,636	111,867	64,483	34,123	13,774	5.12
TOTAL PROVED	489,664	351,508	268,009	211,725	171,692	10.11
PROBABLE	359,686	221,114	152,878	112,944	87,067	12.17
TOTAL PROVED PLUS PROBABLE	849,349	572,622	420,888	324,669	258,759	10.77

Note:

(1) Unit values based on net volumes.

	NET PRESENT VALUES OF FUTURE NET REVENUE AFTER INCOME TAX EXPENSES DISCOUNTED AT (%/year)				
RESERVES CATEGORY	0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)
PROVED:					
Developed Producing	259,804	210,611	180,316	158,274	141,401
Developed Non-Producing	39,223	29,030	23,210	19,327	16,516
Undeveloped	177,230	104,661	60,473	31,821	12,415
TOTAL PROVED	476,257	344,302	263,999	209,423	170,333
PROBABLE	265,029	165,903	116,612	87,632	68,705
TOTAL PROVED PLUS PROBABLE	741,287	510,205	380,612	297,055	239,038

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
AS OF DECEMBER 31, 2016
FORECAST PRICES AND COSTS (1)(2)

RESERVES CATEGORY	REVENUE ($000s)	ROYALTIES ($000s)	OPERATING COSTS ($000s)	DEVELOPMENT COSTS ($000s)	ABANDONMENT AND RECLAMATION COSTS ($000s)	FUTURE NET REVENUE BEFORE INCOME TAX EXPENSES ($000s)	INCOME TAX EXPENSES ($000s)	FUTURE NET REVENUE AFTER INCOME TAX EXPENSES ($000s)
Total Proved	1,259,046	122,277	388,060	201,556	57,489	489,664	13,406	476,257
Total Proved plus Probable	1,977,520	208,162	588,881	269,144	61,984	849,349	108,063	741,287

Notes:

(1) Total revenue includes company revenue before royalty and includes other income.
(2) Royalties include Crown, freehold and overriding royalties and mineral tax.

FUTURE NET REVENUE
BY PRODUCTION GROUP
AS OF DECEMBER 31, 2016
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAX EXPENSES (discounted at 10%/year) ($000s)	UNIT VALUE[1] ($/Boe)
Proved	Light and Medium Crude Oil [2]	89,959	11.96
	Conventional Natural Gas [3]	178,044	9.38
	Coalbed Methane [3]	6	1.70
	Total	268,009	
Proved plus Probable	Light and Medium Crude Oil [2]	154,114	12.96
	Conventional Natural Gas [3]	266,767	9.82
	Coalbed Methane [3]	7	1.67
	Total	420,888	

Notes:

(1) Unit values are based on net reserve volumes.
(2) Including solution gas and other by-products.
(3) Including by-products but excluding solution gas and by-products from oil wells.

Pricing Assumptions – Forecast Prices and Costs

Weighted average historical prices we realized for the year ended December 31, 2016, excluding price risk management activities, were $45.13/Bbl for light and medium crude oil, $2.39/Mcf for natural gas and $17.23/Bbl for NGLs. Sproule employed the following pricing, exchange rate and inflation rate assumptions as of December 31, 2016 in the Sproule Report in estimating reserves data using forecast prices and costs as shown in the table below.

SUMMARY OF WEIGHTED AVERAGE HISTORICAL PRICES FOR 2016 AND PRICING AND INFLATION RATE ASSUMPTIONS FORECAST PRICES AND COSTS (1)

	MEDIUM AND LIGHT CRUDE OIL			NATURAL GAS	NATURAL GAS LIQUIDS			
YEAR	WTI Cushing Oklahoma 40° API ($US/Bbl)	Canadian Light Sweet Crude 40° API ($/Bbl)	Cromer LSB 35° API ($/Bbl)	Alberta AECO-C Spot ($/MMBtu)	Edmonton Propane ($/Bbl)	Edmonton Butane ($/Bbl)	Edmonton Pentanes Plus ($/Bbl)	Exchange Rate ($US/$Cdn) (2)
2016 Actual Benchmarks	43.32	52.80	50.77	2.18	13.60	34.32	55.71	0.755
Forecast Benchmarks								
2017	55.00	65.58	64.58	3.44	22.74	47.60	67.95	0.780
2018	65.00	74.51	73.51	3.27	28.04	55.49	75.61	0.820
2019	70.00	78.24	77.24	3.22	30.64	57.65	78.82	0.850
2020	71.40	80.64	79.64	3.91	32.27	58.80	80.47	0.850
2021	72.83	82.25	81.25	4.00	33.95	59.98	82.15	0.850
2022	74.28	83.90	82.90	4.10	35.68	61.18	83.86	0.850
2023	75.77	85.58	84.58	4.19	37.46	62.40	85.61	0.850
2024	77.29	87.29	86.29	4.29	39.30	63.65	87.39	0.850
2025	78.83	89.03	88.03	4.40	41.19	64.92	89.21	0.850
2026	80.41	90.81	89.81	4.50	43.13	66.22	91.07	0.850
2027	82.02	92.63	91.63	4.61	45.14	67.54	92.96	0.850

Escalated at 2.0% per year thereafter

Notes:

(1) As at December 31, 2016.
(2) Exchange rate used to generate the benchmark reference prices in this table.

Reconciliation of Changes in Reserves

The following table sets forth a reconciliation of our gross reserves as at December 31, 2016, derived from the Sproule Report using forecast prices and cost estimates, reconciled to our gross reserves as at December 31, 2015.

RECONCILIATION OF GROSS RESERVES BY PRINCIPAL PRODUCT TYPE FORECAST PRICES AND COSTS

PROVED RESERVES	LIGHT AND MEDIUM CRUDE OIL (Mbbls)	NATURAL GAS LIQUIDS (Mbbls)	CONVENTIONAL NATURAL GAS (MMcf)	COALBED METHANE (MMcf)	TOTAL OIL EQUIVALENT (MBOE)
December 31, 2015	5,918.5	5,297.0	128,437.0	605.0	32,722.5
Extensions	65.4	450.6	9,088.4	—	2,030.7
Infills	112.1	98.6	2,219.6	—	580.6
Improved Recovery	—	—	—	—	—
Technical Revisions (1)	431.7	(825.7)	8,147.4	(503.4)	880.0
Discoveries	—	—	—	—	—
Acquisitions (3)	13.7	228.7	3,706.3	—	860.1
Dispositions (3)	(1,795.0)	(152.1)	(9,704.7)	—	(3,564.6)
Economic Factors (2)	(162.6)	441.5	2,105.9	(9.6)	628.3
Production	(666.2)	(276.4)	(12,364.1)	(66.7)	(3,014.4)
December 31, 2016	3,917.6	5,262.2	131,635.8	25.3	31,123.3

PROBABLE RESERVES	LIGHT AND MEDIUM CRUDE OIL	NATURAL GAS LIQUIDS	CONVENTIONAL NATURAL GAS	COALBED METHANE	TOTAL OIL EQUIVALENT
	(Mbbls)	(Mbbls)	(MMcf)	(MMcf)	(MBOE)
December 31, 2015	4,325.2	2,261.4	59,148.0	214.0	16,480.3
Extensions	17.5	339.8	7,225.0	—	1,561.5
Infills	147.6	37.1	982.2	—	348.4
Improved Recovery	—	—	—	—	—
Technical Revisions (1)	(105.0)	(97.0)	1,970.5	(209.0)	91.6
Discoveries	—	—	—	—	—
Acquisitions (3)	3.3	60.2	949.0	—	221.7
Dispositions (3)	(1,407.0)	(63.1)	(6,886.6)	—	(2,617.9)
Economic Factors (2)	(15.5)	(221.5)	(5,668.0)	(3.4)	(1,182.2)
Production	—	—	—	—	—
December 31, 2016	2,966.1	2,316.9	57,720.1	1.6	14,903.3

PROVED PLUS PROBABLE RESERVES	LIGHT AND MEDIUM CRUDE OIL	NATURAL GAS LIQUIDS	CONVENTIONAL NATURAL GAS	COALBED METHANE	TOTAL OIL EQUIVALENT
	(Mbbls)	(Mbbls)	(MMcf)	(MMcf)	(MBOE)
December 31, 2015	10,243.7	7,558.4	187,585.0	819.0	49,202.8
Extensions	82.9	790.4	16,313.4	—	3,592.2
Infills	259.7	135.7	3,201.8	—	929.0
Improved Recovery	—	—	—	—	—
Technical Revisions (1)	326.7	(922.7)	10,117.9	(712.4)	971.6
Discoveries	—	—	—	—	—
Acquisitions (3)	17.0	288.9	4,655.3	—	1,081.8
Dispositions (3)	(3,202.0)	(215.2)	(16,591.3)	—	(6,182.4)
Economic Factors (2)	(178.1)	220.0	(3,562.1)	(13.0)	(554.0)
Production	(666.2)	(276.4)	(12,364.1)	(66.7)	(3,014.4)
December 31, 2016	6,883.7	7,579.1	189,355.9	26.9	46,026.6

Notes:

(1) Includes technical revisions due to reservoir performance, geological and engineering changes as well as changes of category from probable to proven.
(2) Includes economic revisions due to changes in economic limits and related to price and royalty factor changes.
(3) Includes production attributable to any acquired interests from the acquisition date to effective date of the report and production realized from disposed interests from the opening balance date to the effective date of disposition.

ADDITIONAL INFORMATION RELATING TO RESERVES DATA

Undeveloped Reserves

Undeveloped reserves are attributed by Sproule in accordance with standards and procedures contained in the COGE Handbook. Proven undeveloped reserves are generally those reserves tested or indicated by analogy to be productive, infill drilling locations and lands contiguous to production. Probable undeveloped reserves are generally those reserves related to infill wells that have not yet been drilled or wells further away from gathering systems requiring relatively high capital to bring on production. This also includes the probable undeveloped wedge from the proved undeveloped locations.

Petrus currently plans to pursue the development of our proved and probable undeveloped reserves within the next four years through ordinary course capital expenditures. In some cases, it will take longer than four years to develop these reserves; however, Petrus expects that the large majority of our booked undeveloped projects will be completed within a three year time frame. There are a number of factors that could result in delayed or cancelled development, including the following: (i) existence of higher priority expenditures; (ii) changing economic conditions (due to pricing, operating and capital expenditure fluctuations); (iii) changing technical conditions (including production anomalies, such as water breakthrough or accelerated depletion); (iv) multi-zone developments (for instance, a prospective formation completion may be delayed until the initial completion is no longer economic); (v) a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and (vi) surface access issues (including those relating to land owners, weather conditions and regulatory approvals). See "*Risk Factors – Reserve Estimates*".

Proved Undeveloped Reserves

The following table discloses, for each product type, the volumes of proved undeveloped reserves that were attributed in each of the most recent three financial years.

Year	Light and Medium Crude Oil (Mbbls)		Conventional Natural Gas (MMcf)		Coalbed Methane (MMcf)		NGLs (Mbbls)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
2014	395.5	1,406.1	563	24,911	—	150	1.4	1,534.9
2015	1,055.0	2,210.0	31,143	57,617	—	318	1,547.3	3,260.5
2016	166.2	1,948.3	6,237	58,059	—	—	269.4	2,770.0

Proved undeveloped reserves have been assigned in areas where the reserves can be estimated with a high degree of certainty. In most instances, proved undeveloped reserves will be assigned on lands immediately offsetting existing producing wells within the same accumulation or pool. Sproule has assigned 14,394.8 MBOE of proved undeveloped reserves in the Sproule Report with $197.3 million of associated undiscounted capital, of which $197.3 million is forecast to be spent in the first three years.

Probable Undeveloped Reserves

The following table discloses, for each product type, the volumes of probable undeveloped reserves that were first attributed in each of the most recent three financial years.

Year	Light and Medium Crude Oil (Mbbls)		Conventional Natural Gas (MMcf)		Coalbed Methane (MMcf)		NGLs (Mbbls)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
2014	631.4	2,100.6	2,994	27,295	—	217	9.6	1,297.7
2015	1,271.7	2,969.0	15,719	36,996	—	58	558.8	1,689.6
2016	163.4	2,249.2	7,057	36,063	—	—	312.9	1,550.5

Probable undeveloped reserves have been assigned in areas where the reserves can be estimated with less certainty. It is equally likely that the actual remaining quantities recovered will be greater or less than the proved plus probable reserves. In most instances probable undeveloped reserves have been assigned on lands in the area with existing producing wells but there is some uncertainty as to whether they are directly analogous to the producing accumulation or pool. Sproule has assigned 9,810.1 MBOE of probable undeveloped reserves in the Sproule Report with $67.6 million of associated undiscounted capital, of which $66.2 million is forecast to be spent in the first three years.

Significant Factors or Uncertainties Affecting Reserves Data

Changes in future commodity prices relative to the forecasts provided under "*Pricing Assumptions*" above could have a negative impact on our reserves and in particular the development of our undeveloped reserves unless future development costs are adjusted in parallel. Other than the foregoing and the factors disclosed or described in the tables above, we expect to fund the development costs of our reserves through a combination of cash flow from operating activities, availability under the Petrus Credit Facilities and/or and equity issuances. There can be no guarantee that funds will be available or that our Board of Directors will allocate funding to develop all of the reserves attributed in the Sproule Report. Failure to develop those reserves could have a negative impact on our future cash flows from operating activities. Interest or other costs of external funding are not included in our reserves and future net revenue estimates and would reduce reserves and future net revenue to some degree depending upon the funding sources utilized. We do not anticipate that interest or other funding costs would make development of any of our properties uneconomic. We do not anticipate any significant economic factors or significant uncertainties will affect any particular components of our reserves data. However, our reserves can be affected significantly by fluctuations in product pricing, capital expenditures, operating costs, royalty regimes and well performance that are beyond our control. See "*Risk Factors*".

Abandonment and Reclamation Costs

Abandonment and reclamation costs for all existing wells (i.e. producing, standing, injection etc.) have been forecast by Petrus at the corporate level and abandonment and reclamation costs for the future proposed development wells have been forecast by Sproule as part of the Sproule Report. These abandonment and reclamation costs have been estimated in the Sproule Report and attributed to all properties that have been assigned reserves in the Sproule Report and have been taken into account by Sproule in determining reserves that should be attributed to a property and in determining the aggregated future net revenue therefrom. No allowance by the Sproule Report was made, however, for the abandonment and reclamation of any pipelines or facilities.

Petrus will be liable for its share of ongoing environmental obligations and for the ultimate reclamation of the surface leases, wells, facilities, and pipelines held by it upon abandonment. Ongoing environmental obligations are expected to be funded out of cash flow.

No estimate of salvage value is netted against the estimated cost. Our model for estimating the amount of future abandonment and reclamation expenditures was done on an individual well and facility level. Estimated expenditures for each well and facility are based on internal estimates using public data and management's experience. Each well and facility are assigned an average cost (by commodity type and well depth) for abandonment and reclamation over a 60 year period. The estimated expenditures are based on current regulatory standards and actual abandonment cost history. Timing of expenditures is based on expected well lives. Facility reclamation costs are generally scheduled to begin shortly before the end of the reserve life of our associated reserves and continue beyond the reserve life under the assumption that decommissioning of plant/facilities are generally mobile assets with a long useful life.

We estimate that we will incur total net reclamation and abandonment costs of $10.3 million, discounted at 10%, to abandon and reclaim all wells ($62.0 million undiscounted). Abandonment and reclamation costs undiscounted and expected to be paid over the next three years totals approximately $1.0 million.

The additional liability associated with pipelines and facility reclamation costs, which were estimated to be $13.0 million as at December 31, 2016, were not deducted in estimating future net revenue in the Sproule Report.

Additional information related to our estimated share of future environmental and reclamation obligations for the working interest properties (including all abandonment and reclamation costs associated with all existing wells, facilities, pipelines and leases) can be found in Petrus' audited financial statements for the year ended December 31, 2016 and the accompanying management's discussion and analysis, which are available on SEDAR at www.sedar.com.

Future Development Costs

The table below sets out the total development costs deducted in the estimation in the Sproule Report of future net revenue attributable to our proved reserves and proved plus probable reserves (using forecast prices and costs).

Year	FORECAST PRICES AND COSTS Proved Reserves ($000s)	Proved Plus Probable Reserves ($000s)
2017	46,496.4	51,236.8
2018	97,460.4	133,359.5
2019	57,599.2	83,180.3
2020	—	1,367.8
2021	—	—
2022	—	—
TOTAL UNDISCOUNTED	201,555.9	269,144.3

We have several different sources of funding to consider in order for financing future development costs: internally generated cash flows from operating activities, debt financing, equity financing and asset dispositions. We currently expect to fund future development costs primarily through cash flows from operating activities. We may rely, to some extent, on debt financing by utilizing the available Petrus Credit Facilities or on equity financing by issuing additional Common Shares. The use of debt or equity financing would be dependent on market conditions, the cost of the capital, the desirability of accelerating our capital expenditure program and the availability of financing on favourable terms. The use of proceeds from asset dispositions would be dependent on prevailing commodity and market conditions which impact the ability to dispose of properties on favourable terms.

OTHER OIL AND NATURAL GAS INFORMATION

Oil and Natural Gas Wells

The following table sets forth the number and status of our wells effective December 31, 2016.

	PRODUCING WELLS				NON-PRODUCING WELLS					
	Oil		Natural Gas		Oil		Natural Gas		Other Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	139	73.5	173	105.7	140	52.8	205	114.0	89	56.4
TOTAL	139	73.5	173	105.7	140	52.8	205	114.0	89	56.4

Notes:

"Gross" wells means the number of wells in which the Corporation has a working interest.
"Net" wells means the aggregate number of wells obtained by multiplying each gross well by the Corporation's percentage working interest therein.
Other Non-producing includes wellbores shut-in for economic reasons, wellbores not capable of production and wellbores used for disposal or injection of water.

Of the non-producing wells, 3 gross (1.2 net) were wells drilled in 2016 that were capable of production and had reserves assigned to them.

Properties with no Attributed Reserves

The following table summarizes, effective December 31, 2016, the gross and net acres of undeveloped properties in which we had an interest and also the number of net acres for which our rights to explore, develop or exploit could expire within one year.

	GROSS ACRES	NET ACRES	NET ACRES EXPIRING WITHIN ONE YEAR
Alberta	182,942	112,615	9,843
TOTAL	**182,942**	**112,615**	**9,843**

Petrus expects that rights to explore, develop and exploit approximately 9,843 net acres of undeveloped land holdings may expire by December 31, 2017. A portion of Petrus' 2017 exploitation and development program may result in extending or eliminating such potential expirations. Petrus closely monitors land expirations as compared to its development program with the strategy of minimizing undeveloped land expirations relating to significant uncertainties that affect the anticipated development or production activities on properties with no contributed reserves.

Forward Contracts

We are exposed to market risks resulting from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of operations. A variety of derivative instruments are used by us to reduce our exposure to fluctuations in commodity prices and foreign exchange rates. We are exposed to losses in the event of default by the counterparties to these derivative instruments. We manage this risk by diversifying our derivative portfolio amongst a number of financially sound counterparties.

We may use certain financial instruments to hedge exposure to commodity price fluctuations on a portion of our crude oil and natural gas production. For further information, see note 10 to our financial statements for the year ended December 31, 2016.

Tax Horizon

Based on Sproule production forecasts, planned capital expenditures and the forecast commodity pricing employed in the Sproule Report, we estimate that we will not be required to pay current income taxes until at least 2021. See "*Risk Factors – Income Taxes*".

Costs Incurred

The following table summarizes capital expenditures incurred by us during the year ended December 31, 2016.

	PROPERTY ACQUISITION COSTS			
	Proved Properties	Unproved Properties	Exploration Costs	Development Costs
TOTAL ($millions)	12,387	—	632	28,614

Drilling Activity

The following table sets forth the gross and net exploration and development wells drilled by us during the year ended December 31, 2016. All wells were drilled in Canada.

	EXPLORATION WELLS		DEVELOPMENT WELLS	
	Gross	Net	Gross	Net
Light and Medium Crude Oil	—	—	1	0.35
Natural Gas	—	—	10	6.96
Service	—	—	—	—
Stratigraphic Test	—	—	—	—
Dry	—	—	—	—
TOTAL	—	—	11	7.31

Planned Capital Expenditures

In January 2017 Petrus announced our planned capital expenditure budget of $50 to $60 million (excluding acquisitions and dispositions) for the 2017 fiscal year which is primarily focused on liquids rich Cardium gas development projects with the majority of the capital directed to drilling, completions and tie-ins (approximately 65%). This capital budget includes drilling 16 gross (11.7 net) Cardium wells in the Ferrier/Strachan area. Petrus' 2017 capital budget also provides for investment in facilities and the processing and compression capability of the Ferrier gas plant is expected to be doubled to reach a capacity of approximately 60 MMcf/d by the fourth quarter of 2017.

With the current volatility of commodity prices, we continue to actively monitor our 2017 capital expenditure plans in the context of expected cash flows from operating activities, potential service cost adjustments and portfolio allocation in order to prudently manage and maintain financial flexibility.

Production Estimates

The following table discloses for each product type the total volume of production estimated by Sproule in the Sproule Report for 2017 in the estimates of future net revenue from gross proved and gross proved plus probable reserves disclosed above.

	Light and Medium Crude Oil (Bbls/d)	NGLs (Bbls/d)	Conventional Natural Gas (Mcf/d)	Total Oil Equivalent (BOE/d)
PROVED				
Developed Producing	835.1	1,208.3	29,284	6,924.1
Developed Non-Producing	19.6	127.7	3,082	661.0
Undeveloped	52.1	215.1	4,087	948.4
TOTAL PROVED	906.8	1,551.3	36,455	8,533.9
PROBABLE	130.0	131.0	3,051	769.5
TOTAL PROVED PLUS PROBABLE	1,036.9	1,682.3	39,506	9,303.5

Production History

The following table discloses, on a quarterly basis for the year ended December 31, 2016, certain information in respect of our production, product prices received, royalties paid, operating expenses and resulting netback.

	Quarter Ended 2016				Year ended
	Mar. 31	**June 30**	**Sept. 30**	**Dec. 31**	**Dec. 31, 2016**
Average Daily Production [1]					
Light and Medium Crude Oil (Bbls/d)	2,218	2,200	1,419	1,452	1,820
Natural Gas Liquids (Bbls/d)	694	723	680	922	755
Conventional Natural Gas (MMcf/d)	35,456	33,071	30,009	37,327	33,964
Combined (BOE/d)	8,821	8,435	7,100	8,596	8,236
Average Net Production Prices Received					
Light and Medium Crude Oil ($/Bbl)	34.52	46.68	44.50	59.42	45.13
Natural Gas Liquids ($/Bbl)	18.18	8.47	15.56	24.56	17.23
Conventional Natural Gas ($/Mcf)	2.01	1.64	2.53	3.29	2.39
Combined ($/BOE)	18.18	19.32	21.06	26.97	21.40
Royalties Paid					
Light and Medium Crude Oil ($/Bbl)	2.99	3.28	6.85	6.41	4.52
Natural Gas Liquids ($/Bbl)	5.45	2.54	4.67	7.37	5.17
Conventional Natural Gas ($/Mcf)	0.07	0.08	0.09	0.07	0.06
Combined ($/BOE)	3.08	2.26	2.99	3.52	2.97
Production Costs [2]					
Light and Medium Crude Oil ($/Bbl)	16.12	13.73	15.06	12.14	14.40
Natural Gas Liquids ($/Bbl)	12.88	10.44	7.86	4.78	8.68
Conventional Natural Gas ($/Mcf)	1.26	1.14	0.89	0.59	0.96
Combined ($/BOE)	10.14	8.95	7.53	5.13	7.96
Operating Netback [3]					
Light and Medium Crude Oil ($/Bbl)	15.41	29.67	22.59	40.87	26.21
Natural Gas Liquids ($/Bbl)	(0.16)	(4.52)	3.03	12.41	3.38
Conventional Natural Gas ($/Mcf)	0.68	0.42	1.55	2.69	1.36
Combined ($/BOE)	5.09	8.23	10.61	18.42	10.58

Notes:

(1) Before the deduction of royalties.
(2) Production costs are composed of direct costs incurred to operate both oil and natural gas wells. A number of assumptions are required to allocate these costs between product types.
(3) Operating Netback is calculated by deducting royalties paid and production costs, including transportation costs, from prices received, excluding the effects of hedging. See "Non-GAAP Financial Measures."

Production Volume by Field

The following table indicates the average daily net production from our fields for the year ended December 31, 2016.

	Light and Medium Crude Oil (Bbls/d)	NGLs (Bbls/d)	Conventional Natural Gas (Mcf/d)	Total Oil Equivalent (BOE/d)	Percentage (%)
Alberta					
Central Alberta	604	220	8,929	2,312	28.1
Ferrier	483	555	15,949	3,696	44.9
Foothills	403	—	7,670	1,682	20.4
Peace River[1]	299	10	1,416	545	6.6
TOTAL	1,820	755	33,964	8,236	100.3

[1] Peace River assets were divested July 8, 2016.

CAPITAL STRUCTURE

Share Capital

We are authorized to issue an unlimited number of Common Shares and an unlimited number of Preferred Shares. We also have Old Petrus Warrants outstanding. A description of our share capital is set forth below. For a complete description of our share capital, reference should be made to our articles, a copy of which has been filed on our SEDAR profile at *www.sedar.com*.

Common Shares

The holders of Common Shares are entitled to one vote at all meetings of our shareholders except at meetings of which only holders of a specified class of shares are entitled to vote. The holders of Common Shares are entitled to receive, subject to the prior rights and privileges attaching to any other class of our shares, such dividends as may be declared by us. Holders of Common Shares are entitled upon any liquidation, dissolution or winding-up of Petrus, subject to the prior rights and privileges attaching to any other class of our shares, to receive the remaining property and assets of the Corporation.

Preferred Shares

The Preferred Shares are issuable in series and the designation of, and the rights or privileges, restrictions and conditions attached to any series of Preferred Shares are to be established by our Board of Directors prior to the issuance thereof. The Preferred Shares have a preference over the Common Shares and any of our classes of shares ranking junior to the Preferred Shares with respect to the payment of dividends and the distribution of our assets in the event of liquidation, dissolution or winding-up of us or any other distribution of our assets among our shareholders for the purpose of winding-up our affairs. No series of Preferred Shares has been designated to date and there are no Preferred Shares outstanding.

Stock Options

As at December 31, 2016 there were 1,976,580 Stock Options and Old Petrus Options outstanding (the "**Outstanding Options**"), of which 917,917 were exercisable. Each Outstanding Option currently entitles the holder to acquire one Common Share at a price ranging from $1.98 to $16.00. The weighted average remaining life of the Outstanding Options is 0.85 years from December 31, 2016.

Performance Warrants

As at December 31, 2016 there were 429,667 Old Petrus Warrants outstanding, of which 252,409 were exercisable. Each Old Petrus Warrant currently entitles the holder to acquire one Common Share at a price ranging from $8.00 to $9.00, subject to the following conditions: (i) one-third of the Old Petrus Warrants may be exercised after our stock price exceeds $12.80; (ii) one-third of the Old Petrus Warrants may be exercised after our stock price exceeds $16.00; and (iii) one-third of the Old Petrus Warrants may be exercised after our stock price exceeds $20.00. The weighted average remaining life of the Old Petrus Warrants is 0.60 years from December 31, 2016 which is five years from the date of each respective grant.

DIVIDEND POLICY

Dividends and Dividend Policy

No dividends have been declared or paid on the Common Shares or Old Petrus Shares since incorporation. Any decision to pay dividends on the Common Shares will be made by the Board of Directors on the basis of the Corporation's earnings, financial requirements and other conditions existing at such future time. See "*Risk Factors – Substantial Capital Requirements*"**.**

Other than as detailed below, there are no restrictions in our articles or elsewhere which could prevent us from paying dividends. It is not contemplated that any dividends will be paid on the Common Shares in the immediate future, as it is anticipated that all available funds will be invested to finance the growth of our business. The Board of Directors will determine if, and when, dividends will be declared and paid in the future from funds properly applicable to the payment of dividends based on our financial position at the relevant time. Any decision to pay dividends on the Common Shares will be made by the directors on the basis of Petrus' earnings, financial requirements and other factors existing at such future time, including 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. All of the Common Shares will be entitled to an equal share in any dividends declared and paid.

Under the terms of the Petrus Credit Facilities, the Corporation may not, without the prior written consent of a majority of its lenders, pay dividends or capital distributions in the event that such payment would result in a breach of the provisions of the Petrus Credit Facilities.

MARKET FOR OUR SECURITIES

The Common Shares trade on the TSX under the symbol "PRQ". The following table sets forth the price range and trading volume of the Common Shares on the TSX for the periods indicated. The Common Shares did not commence trading on the TSX until February 8, 2016.

	Price Range ($)		
Period	**Low**	**High**	**Trading Volume**
2016			
February (Feb 8 – Feb 29)	$2.81	$4.99	462,038
March	$2.36	$2.90	1,017,251
April	$1.80	$2.57	508,668
May	$1.90	$2.54	245,851
June	$1.73	$1.99	357,124
July	$1.75	$2.24	1,400,690
August	$2.02	$2.55	1,119,007
September	$1.83	$2.15	1,040,240
October	$1.85	$2.09	764,709
November	$1.71	$2.65	1,591,448
December	$2.43	$3.43	1,109,072
2017			
January	$2.77	$3.30	1,009,257
February	$2.50	$2.95	540,538
March (Mar 1 – 8)	$2.17	$2.63	146,156

Prior Sales

During the year ended December 31, 2016, we granted an aggregate of 791,580 Options to acquire an aggregate of 791,580 Common Shares with a weighted average exercise price of $1.98 on November 17, 2016. Other than such Options, we did not issue any securities, other than Common Shares, during the year ended December 31, 2016.

DIRECTORS AND OFFICERS

The name, municipality of residence, principal occupation for the prior five years and position with us of each of our directors and officers as of the date hereof are as follows:

Name and Residence	Position	Principal Occupation During Previous Five Years
Neil Korchinski Alberta, Canada	President and Chief Executive Officer and a Director (since November 7, 2016)	Mr. Korchinski was Vice President Engineering and Chief Operating Officer of Petrus from February 2, 2016 to November 7, 2016 and held that position at Old Petrus from August 8, 2011 to February 2, 2016.
Patrick Arnell[(1)(2)(3)] Alberta, Canada	Director (since November 25, 2015)	Mr. Arnell was a director of Old Petrus from August 3, 2011 to February 2, 2016. Mr. Arnell is an independent businessman and is currently also the Chairman and Chief Executive Officer of Orix Investments Inc., a private investment company headquartered in Calgary, Alberta.
Donald Cormack[(1)(3)] Alberta, Canada	Director (since November 25, 2015)	Mr. Cormack was a director of Old Petrus from October 8, 2014 to February 2, 2016. Mr. Cormack was a partner with PricewaterhouseCoopers LLP, including as Calgary audit practice leader from 1997 to 2007, until his retirement in 2012. Mr. Cormack is currently also a director of the Walton Group public registrants.
Donald Gray[(2)(3)] Arizona, United States	Director (since November 25, 2015)	Mr. Gray is a private investor and Chairman of Petrus. He was director and the Chairman of Old Petrus from December 13, 2010 to February 2, 2016. Mr. Gray was a founding partner and President of EIQ Capital Corp., a private capital management company, from May 2007 to September 2013. Mr. Gray is also a director and Chairman of Peyto Exploration & Development Corp. and Gear Energy Ltd, both TSX-listed oil and natural gas companies.
Brian Minnehan[(4)(5)] Texas, United States	Director (since November 25, 2015)	Mr. Minnehan was a director of Old Petrus from January 14, 2015 to February 2, 2016. He is a Partner of NGP, a private equity fund focused on investments in energy, where he has been since 2007. He currently sits on the board of directors of Northern Blizzard Resources Inc. a TSX-listed oil and natural gas company, and several private oil and natural gas companies.
Peter Verburg Alberta, Canada	Director (since November 25, 2015)	Mr. Verburg was a director of Old Petrus from December 2010 to February 2, 2016 and was a founding partner and, since September 2013, has been President of EIQ Capital Corp., a private investment firm. Prior thereto, Mr. Verburg was Managing Director of EIQ Capital Corp. since March 2008; and Vice President, Investment Banking of GMP Securities L.P. since February 2005. Mr. Verburg is also a director of Gear Energy Ltd., a TSX oil and natural gas listed company.
Jeffrey Zlotky[(4) (5)] Texas, United States	Director (since December 29, 2015)	Mr. Zlotky has been General Counsel of Natural Gas Partners, a private equity fund focused on investments in energy, since 2015. Prior thereto, Mr. Zlotky spent his entire professional career at the law firm of Thompson & Knight LLP, a Texas based law firm, where he worked in their Corporate and Securities Department and specialized in corporate transactions involving the oil and natural gas industry and private equity. He served in a variety of increasing management positions at the law firm, including as its global Managing Partner from 2009 to 2012.
Stephen White[(1) (5)] Alberta, Canada	Director (since February 2, 2016)	Mr. White serves on the boards of directors and audit committees of several public and private corporations. He was President and Chief Financial Officer of Fort Chicago Energy Management Ltd., the general partner of Fort Chicago Energy Partners L.P., from its inception in 1997 until January 1, 2003 when he assumed the role of President and Chief Executive Officer, the position he held until his retirement as President and Chief Executive Officer of Veresen Inc. effective November 20, 2012.
Cheree Stephenson	Vice President, Finance	Ms. Stephenson is the Vice President Finance and Chief Financial Officer of

Name and Residence	Position	Principal Occupation During Previous Five Years
Alberta, Canada	and Chief Financial Officer (since November 25, 2015)	Petrus and held the same position at Old Petrus from August 8, 2011 to February 2, 2016.
Brett Booth Alberta, Canada	Vice President, Land (since January 23, 2017)	Mr. Booth was Land Manager of Petrus from February 2, 2016 to January 23, 2017 and held that position at Old Petrus from December 1, 2011 to February 2, 2016.
Ross Keilly Alberta, Canada	Vice President, Exploration (since January 23, 2017)	Mr. Keilly was Senior Geologist of Petrus from February 2, 2016 to January 23, 2017 and held that position in Old Petrus from March 15, 2012 to February 2, 2016.
Marcus Schlegel Alberta, Canada	Vice President, Engineering (since January 23, 2017)	Mr. Schlegel was Exploitation Manager of Petrus from February 2, 2016 to January 23, 2017 and held that position at Old Petrus from July 9, 2014 to February 2, 2016. Previous to his time at Old Petrus, Mr. Schlegel worked as a Professional Engineer for CanEra Energy Corp., CNRL and Anadarko Canada in exploitation, operations and production engineering roles.

Notes:

(1) Member of the Audit Committee.
(2) Member of the Reserves Committee.
(3) Member of the Compensation Committee.
(4) Mr. Minnehan is a Managing Director of NGP, was the nominee director of NGP pursuant to the shareholders' agreement dated June 29, 2012 among the Corporation, NGP, certain members of management and the Board and certain other shareholders (the "**Old Petrus Shareholders' Agreement**") and is NGP's current nominee pursuant to the Nomination Rights Agreement. Mr. Zlotky was appointed to the Board of Directors on February 2, 2016 following the completion of the Arrangement pursuant to the Nomination Rights Agreement. See "*Material Contracts - Agreements with NGP - Nomination Rights Agreement*".
(5) The committees of the Board of Directors are constituted in compliance with NI 52-110 (as defined below) and National Instrument 58-101 – *Disclosure of Corporate Governance Practices*.

As a group, our directors and executive officers beneficially own, control or direct, directly or indirectly, 18.3 million Common Shares, representing approximately 37% of the outstanding Common Shares. Each above listed director will continue to hold office until the next annual general meeting of the Corporation or until a successor is duly elected or appointed in accordance with the ABCA, unless their office is earlier vacated.

Corporate Cease Trade Orders, Bankruptcies or Penalties or Sanctions

To our knowledge, none of our directors or executive officers (nor any personal holding company of any of such persons) is, as of the date of this Annual Information Form, or was within ten years before the date of this Annual Information Form, a director, chief executive officer or chief financial officer of any company (including us), that was subject to a cease trade order (including a management cease trade order), an order similar to a cease trade order or an order that denied the relevant company access to any exemption under securities legislation, in each case that was in effect for a period of more than thirty consecutive days (collectively, an "**Order**") that was issued while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer, or was subject to an Order that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer.

Other than as set out below, to our knowledge, none of our directors or executive officers (nor any personal holding company of any of such persons), or Shareholder holding a sufficient number of our securities to affect materially the control of us is, as of the date of this Annual Information Form, or has been within the ten years before the date of this Annual Information Form, a director or executive officer of any company (including us) that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets.

Stephen H. White was a director of Lignol Energy Corporation ("**Lignol**"), a biofuels technology company listed on the TSX Venture Exchange. On August 22, 2014, a secured creditor of Lignol appointed a receiver over the assets and undertaking of Lignol.

To our knowledge, none of our directors or executive officers (nor any personal holding company of any of such persons), or Shareholders holding a sufficient number of our securities to affect materially the control of us is, has, within the ten years before the date of this Annual Information Form, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director, executive officer or Shareholder.

To our knowledge, none of our directors or executive officers (nor any personal holding company of any of such persons), or Shareholders holding a sufficient number of our securities to affect materially the control of us, has been subject to any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority or any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

Conflicts of Interest

Our directors and officers may, from time to time, be involved with the business and operations of other oil and natural gas issuers, in which case a conflict may arise. See "*Risk Factors – Conflicts of Interest"*.

Circumstances may arise where members of our Board of Directors serve as directors or officers of corporations which are in competition to our interests. No assurances can be given that opportunities identified by such board members will be provided to us.

The ABCA provides that in the event a director has an interest in a contract or proposed contract or agreement, the director shall disclose his interest in such contract or agreement and shall refrain from voting on any matter in respect of such contract or agreement unless otherwise provided under the ABCA. To the extent that conflicts of interests arise, such conflicts will be resolved in accordance with the provisions of the ABCA.

AUDIT COMMITTEE

The Audit Committee is comprised of Messrs. Cormack, Arnell and White. Mr. Cormack is the Chairman of the Audit Committee. The Audit Committee operates under a written charter that sets out its responsibilities and composition requirements. A copy of the charter is attached to this Annual Information Form as Schedule "A" and a copy of the mandate of the Board of Directors is attached as Schedule "D".

The following chart sets out the assessment, within the meaning of National Instrument 52-110 – Audit Committees ("**NI 52-110**"), of each audit committee member's independence, financial literacy and relevant educational background and experience supporting such financial literacy.

Name, Province and Country of Residence	Independent	Financially Literate	Relevant Education and Experience
Mr. Donald Cormack (Chair)	Yes	Yes	Mr. Cormack was a partner with PricewaterhouseCoopers LLP from 1997 until his retirement in the summer of 2012, including as Calgary audit practice leader from 1997 to 2007. He has extensive financial accounting and reporting experience with both private and public companies of all sizes covering regulatory compliance, risk management, acquisitions, corporate restructuring, internal controls and

Name, Province and Country of Residence	Independent	Financially Literate	Relevant Education and Experience
			governance in Canada and the U.S. Mr. Cormack is a director of the Calgary Police Foundation and past director of The Calgary Foundation and Alberta Health Services. Mr. Cormack is currently also a director of the Walton Group public registrants. He is a Chartered Professional Accountant, a graduate of the Institute of Corporate Directors Program and has a Bachelor of Commerce degree from the University of Saskatchewan.
Mr. Patrick Arnell	Yes	Yes	Mr. Arnell is currently the Chairman and Chief Executive Officer of Orix Investments Inc., a private investment company headquartered in Calgary, Alberta. Additionally, Mr. Arnell has been an independent businessman since 2005; and, prior thereto, President and majority owner of Rayton Packaging Inc. from 1992 to 2005.
Mr. Stephen White	Yes	Yes	Mr. White currently serves on the boards of directors and audit committees of several public and private corporations. He was President and Chief Financial Officer of Fort Chicago Energy Management Ltd., the general partner of Fort Chicago Energy Partners L.P., from its inception in 1997 until January 1, 2003 when he assumed the role of President and Chief Executive Officer, the position he held until his retirement as President and Chief Executive Officer of Veresen Inc. effective November 20, 2012.

Auditor's Fees

On November 9, 2011, Old Petrus engaged the services of Ernst & Young LLP, Chartered Professional Accountants for the provision of auditor services. The table below summarizes the fees billed by Ernst & Young LLP for the years ended December 31, 2016 and December 31, 2015, respectively.

Year	Audit Fees (1)	Audit-Related Fees (2)	Tax Fees (3)	All Other Fees(4)
2016	$137,000	$63,500	$14,500	$7,500
2015	$140,000	$66,700	$44,300	$112,400

Notes:

(1) Audit fees include fees billed regarding the annual audit of the financial statements.
(2) Audit-related fees include amounts billed for assurance related services that are reasonably related to the performance of the audit of financial statements that are not reported under "Audit fees".
(3) Fees in connection with preparation of Canadian tax returns.
(4) Other fees charged by the auditors, including other non-audit products and services.

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 and with respect to the pricing and taxation of oil and natural gas through agreements among the governments of Canada and Alberta all of which should be carefully considered by investors in the oil and natural gas industry. All current legislation is a matter of public record and we are unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and natural gas industry in western Canada.

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^3 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.

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, NGLs, 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% of the province's mineral rights. The remaining 19% 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 this 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 10 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 5% 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 NGLs), 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^3 (40 BOE/d or 345,500 m^3 of gas per month), the royalty rate will move to a sliding scale (based on volume and price) with a minimum royalty rate of 5%. 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 Alberta Energy Regulator ("**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 1% and 9% 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 1% 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 9% 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 1% and 9% and the net revenue royalty based on the net revenue royalty rate. Net revenue royalty rates start at 25% and increase for every dollar of market price of oil increase above $55 up to 40% 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%. 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% and a minimum royalty rate of 5%.

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 4% 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 5% 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 5% 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 5% 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 5% 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.

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 greenhouse gas ("**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 the replacement of 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% 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% 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 Region 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 Dear Region Plan and Upper Athabasca Region Plan have not been started.

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:

(1) 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 licencee eligibility approval if appropriate in the circumstances.

(2) 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.

(3) 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:

(1) The licensee already has an LMR of 2.0 or higher;
(2) The acquisition will improve the licensee's LMR to 2.0 or higher; or
(3) 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 5 years. As of April 1, 2015, each licensee is required to bring 20% of its inactive wells into compliance every year, either by reactivating or by suspending the wells in accordance with *Directive 013* or by abandoning them in accordance with *Directive 020: Well Abandonment*. The list of current wells subject to the IWCP is available on the AER's Digital Data Submission system. The AER has 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% of licensees operating in the province having met their annual quota.

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% 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 constitutes 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% reduction target established in the Copenhagen Accord with an NDC of 30% 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 2% from their baseline in the fourth year of commercial operation, 4% of their baseline in the fifth year, 6% of their baseline in the sixth year, 8% of their baseline in the seventh year, 10% of their baseline in the eighth year, and 12% 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% in 2016 and 20% 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 10 megatonne limit.

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% 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.

RISK FACTORS

Investors should carefully consider the risk factors set out below and consider all other information contained herein and in the Corporation's other public filings before making an investment decision. The risks set out below are not an exhaustive list and should not be taken as a complete summary or description of all the risks associated with the Corporation's business and the oil and natural gas business generally.

Exploration, Development and Production Risks

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

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, shut-ins of 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.

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

Oil and natural gas production operations are also subject to 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 the Corporation's business, financial condition, results of operations and prospects.

As is standard industry practice, the Corporation is not fully insured against all risks, nor are all risks insurable. Although the Corporation maintains liability insurance in an amount that it considers consistent with industry practice, liabilities associated with certain risks could exceed policy limits or not be covered. In either event, the Corporation could incur significant costs.

Weakness in the Oil and Natural Gas Industry

Recent market events and conditions, including global excess oil and natural gas supply, recent actions taken by the Organization of the Petroleum Exporting Countries ("**OPEC**"), slowing growth in emerging economies, market volatility and disruptions in Asia, sovereign debt levels and political upheavals in various countries have caused significant weakness and volatility in commodity prices. These events and conditions have caused a significant decrease in the valuation of oil and 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 additional downward price pressure on oil and gas produced in Western Canada and uncertainty and reduced confidence in the oil and gas industry in Western Canada. Lower commodity prices may also affect the volume and value of the Corporation's reserves, rendering certain reserves uneconomic. In addition, lower commodity prices have restricted, and are anticipated to continue to restrict, the Corporation's cash flow resulting in a reduced capital expenditure budget. Consequently, the Corporation may not be able to replace its production with additional reserves and both the Corporation's production and reserves could be reduced on a year over year basis. Any decrease in value of the Corporation's reserves may reduce the borrowing base under its credit facilities, which, depending on the level of the Corporation's indebtedness, could result in the Corporation having to repay a portion of its indebtedness. Given the current market conditions and the lack of confidence in the Canadian oil and gas industry, the Corporation may have difficulty raising additional funds or if it is able to do so, it may be on unfavourable and highly dilutive terms.

Prices, Markets and Marketing

Numerous factors beyond the Corporation's control do, and will continue to, affect the marketability and price of oil and natural gas acquired, produced, or discovered by the Corporation. The Corporation's ability to market its oil and natural gas may depend upon its ability to acquire capacity on pipelines that deliver natural gas to commercial markets or contract for the delivery of crude oil by rail. Deliverability uncertainties related to the distance the Corporation's reserves are from pipelines, railway lines, processing and storage facilities; operational problems affecting pipelines, railway lines and facilities; and government regulation relating to prices, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business may also affect the Corporation.

Prices for oil and natural gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors beyond the control of the Corporation. These factors include economic and political conditions in the United States, Canada, Europe, China and emerging markets, the actions of OPEC, governmental regulation, political stability in the Middle East, Northern Africa and elsewhere, the foreign supply and demand of oil and natural gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Prices for oil and natural gas are also subject to the availability of foreign markets and the Corporation's ability to access such markets. Oil prices are expected to remain volatile as a result of global excess supply due to the increased growth of shale oil production in the United States, the decline in global demand for exported crude oil commodities, OPEC's recent decisions pertaining to the oil production of OPEC member countries, and non-OPEC member countries' decisions on production levels, among other factors. A material decline in prices could result in a reduction of the Corporation's net production revenue. The economics of producing from some wells may change because of lower prices, which could result in reduced production of oil or natural gas and a reduction in the volumes and the value of the Corporation's reserves. The Corporation might also elect not to produce from certain wells at lower prices.

All these factors could result in a material decrease in the Corporation's expected net production revenue and a reduction in its oil and natural gas production, development and exploration activities. Any substantial and extended decline in the price of oil and natural gas would have an adverse effect on the Corporation's carrying value of its reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

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

See "*Weakness in the Oil and Gas Industry*".

Market Price of Common Shares

The trading price of securities of oil and natural gas issuers is subject to substantial volatility often based on factors related and unrelated to the financial performance or prospects of the issuers involved. Factors unrelated to Petrus' performance could include macroeconomic developments nationally, within North America or globally, domestic and global commodity prices or current perceptions of the oil and natural gas market. Similarly, the market price of the Common Shares could be subject to significant fluctuations in response to variations in our operating results, financial condition, liquidity and other internal factors. Accordingly, the price at which the Common Shares will trade cannot be accurately predicted.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

The Corporation considers acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions depends on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner and the Corporation's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Corporation. The integration of acquired businesses may require substantial management effort, time and resources diverting management's focus from other strategic opportunities and operational matters. Management continually assesses the value and contribution of services provided by third parties and assets required to provide such services. In this regard, non-core assets may be periodically disposed of so the Corporation can focus its efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain non-core assets of the Corporation may realize less on disposition than their carrying value on the financial statements of the Corporation.

Political Uncertainty

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

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. Some European countries have also experienced the rise of anti-establishment political parties and public protests held against open-door immigration policies, trade and globalization. To the extent that certain political actions taken in North America, Europe and elsewhere in the world result in a marked decrease in free trade, access to personnel and freedom of movement it could have an adverse effect on the Corporation's ability to market its products internationally, increase costs for goods and services required for the Corporation's operations, reduce access to skilled labour and negatively impact the Corporation's business, operations, financial conditions and the market value of the Common Shares.

Operational Dependence

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

In addition, due to the current low and volatile commodity prices, many companies, including companies that may operate some of the assets in which the Corporation has an interest, may be in financial difficulty, which could impact their ability to fund and pursue capital expenditures, carry out their operations in a safe and effective manner and satisfy regulatory requirements with respect to abandonment and reclamation obligations. If companies that operate some of the assets in which the Corporation has an interest fail to satisfy regulatory requirements with respect to abandonment and reclamation obligations the Corporation may be required to satisfy such obligations and to seek 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, the Corporation potentially becoming subject to additional liabilities relating to such assets and the Corporation having difficulty collecting revenue due from such operators or recovering amounts owing to the Corporation from such operators for their share of abandonment and reclamation obligations. Any of these factors could have a material adverse affect on the Corporation's financial and operational results.

Project Risks

The Corporation manages a variety of small and large projects in the conduct of its business. Project delays may delay expected revenues from operations. Significant project cost overruns could make a project uneconomic. The Corporation's ability to execute projects and market oil and natural gas depends upon numerous factors beyond the Corporation's 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, hydraulic fracturing, and waterfloods or the Corporation's ability to dispose of water used or removed from strata at a reasonable cost and in accordance with applicable environmental regulations;
- the effects of inclement weather;
- the availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- regulatory changes;
- the availability and productivity of skilled labour; and
- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

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

Gathering and Processing Facilities, Pipeline Systems and Rail

We deliver our products through gathering and processing facilities and pipeline systems (some of which we do not own) and by rail. The amount of oil and natural gas that the Corporation can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering and processing facilities, pipeline systems and railway lines. In 2015, Petrus experienced temporary interruptible and firm service curtailments on TransCanada Corporation's Nova Gas Transmission system. The lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to produce and market oil and natural gas production. In addition, the pro-rationing of capacity on inter-provincial pipeline systems continues to affect the ability to export oil and natural gas. Unexpected shut downs or curtailment of capacity of pipelines for maintenance or integrity work or because of actions taken by regulators could also affect Petrus' production, operations and financial results. Furthermore, producers are increasingly turning to rail as an alternative means of transportation. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays 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 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 and imposed a per tonne levy of $1.65 on crude oil shipped by rail to compensate victims and for environmental cleanup in the event of a railway accident. In addition to this legislation, new regulations have implemented the TC-117 standard for all rail tank cars carrying flammable liquids which formalized the commitment to retrofit, and 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.

A portion of Petrus' production may, from time to time, be processed through facilities owned by third parties' over which we do not have control. 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 discontinuation or decrease of operations could have a materially adverse effect on the Corporation's ability to process its production and deliver the same for sale.

Competition

The petroleum industry is competitive in all of its phases. The Corporation competes with numerous other entities in the exploration, development, production and marketing of oil and natural gas. The Corporation's competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than those of the Corporation. Some of these companies not only explore for, develop and produce oil and natural gas, but also carry on refining operations and market oil and natural gas on an international basis. As a result of these complementary activities, some of these competitors may have greater and more diverse competitive resources to draw on than the Corporation. The Corporation's ability to increase its reserves in the future will depend not only on its ability to explore and develop its present properties, but also on its ability to select and acquire other suitable producing properties or prospects for exploratory drilling. Competitive factors in the distribution and marketing of oil and natural gas include price, process, and reliability of delivery and storage.

Cost of New Technologies

The petroleum industry is characterized by rapid and significant technological advancements and introductions of new products and services utilizing new technologies. Other 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 us. 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 the Corporation or implemented in the future may become obsolete. In such case, Petrus' business, financial condition and results of operations could be affected adversely and materially. If we are unable to utilize the most advanced commercially available technology, our business, financial condition and results of operations could also be adversely affected in a material way.

Alternatives to and Changing Demand for Petroleum Products

Full 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, natural gas and other liquid hydrocarbons. Petrus 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.

Regulatory

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, royalties and the exportation of oil and natural gas. Amendments to these controls and regulations may occur from time to time in response to economic or political conditions. See "*Industry Conditions*". The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for crude oil and natural gas and increase the Corporation's costs, either of which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In order to conduct oil and natural gas operations, the Corporation will require regulatory permits, licenses, registrations, approvals and authorizations from various governmental authorities at the provincial and federal level. There can be no assurance that the Corporation 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, certain federal legislation such as the *Competition Act* and the *Investment Canada Act* could negatively affect the Corporation's business, financial condition and the market value of the Common Shares or its assets, particularly when undertaking, or attempting to undertake, acquisition or disposition activity.

Royalty Regimes

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

Hydraulic Fracturing

Hydraulic fracturing involves the injection of water, sand and small amounts of additives under pressure into rock formations to stimulate the production of oil and natural gas. Specifically, hydraulic fracturing enables the production of commercial quantities of oil and natural gas from reservoirs that were previously unproductive. Any new laws, regulations or permitting requirements regarding hydraulic fracturing could lead to operational delays, increased operating costs, third party or governmental claims, and could increase the Corporation's costs of compliance and doing business as well as delay the development of oil and natural gas resources from 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 the Corporation is ultimately able to produce from its reserves.

Waterflood

The Corporation undertakes or intends 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 the Corporation needs to have 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 the Corporation 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 the Corporation is unable to access such water it may not be able to undertake waterflooding activities, which may reduce the amount of oil and natural gas that the Corporation is ultimately able to produce from its reservoirs. In addition, the Corporation may undertake certain waterflood programs that ultimately prove unsuccessful in increasing production from the reservoir and as a result have a negative impact on the Corporation's results of operations.

Environmental

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

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

Liability Management

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 obligation. 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 the Corporation's deemed assets to deemed liabilities or other changes to the requirements of liability management programs may result in significant increases to the Corporation's compliance requirement. In addition, the liability management system may prevent or interfere with the Corporation's ability to acquire or dispose of assets as both the vendor and the purchaser of oil and 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 and 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*".

Climate Change

The Corporation's exploration and production facilities and other operations and activities emit greenhouse gases which may require the Corporation to comply with GHG emissions legislation at the provincial or federal level. Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place. As a signatory to the UNFCCC and a 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% 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 new GHG emission reduction targets of a 30% 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 come 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. The direct or indirect costs of compliance with these regulations may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. Some of the Corporation's significant facilities may ultimately be subject to future regional, provincial and/or federal climate change regulations to manage GHG emissions. In addition, concerns about climate change have resulted in a number of environmental activists and members of the public opposing the continued exploitation and development of fossil fuels. Given the evolving nature of the debate related to climate change and the control of GHG and resulting requirements, it is not possible to predict the impact on the Corporation and its operations and financial condition. See "*Industry Conditions - Climate Change Regulation*".

Variations in Foreign Exchange Rates and Interest Rates

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

To the extent that Petrus engages 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 the Common Shares.

Substantial Capital Requirements

We anticipate making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. As future capital expenditures will be financed out of cash generated from operations, borrowings and possible future equity sales, Petrus' ability to do so is dependent on, among other factors:

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

Further, if our revenues or reserves decline, we may not have access to the capital necessary to undertake or complete future drilling programs. The current conditions in the oil and natural gas industry have negatively impacted the ability of oil and natural gas companies to access additional financing. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Corporation. We may be required to seek additional equity financing on terms that are highly dilutive to existing shareholders. The inability of Petrus to access sufficient capital for our operations could have a material adverse effect on our business financial condition, results of operations and prospects.

Additional Funding Requirements

Our cash flow from reserves may not be sufficient to fund Petrus' ongoing activities at all times and from time to time, we may require additional financing in order to carry out our oil and natural gas acquisition, exploration and development activities. Failure to obtain financing on a timely basis could cause Petrus to forfeit our interest in certain properties, miss certain acquisition opportunities and reduce or terminate our operations. Due to the conditions in the oil and natural gas industry and/or global economic volatility, we may, from time to time, have restricted access to capital and increased borrowing costs. The current conditions in the oil and natural gas industry have negatively impacted the ability of oil and natural gas companies to access additional financing.

Continued depressed oil and natural gas prices have caused decreases, and may cause further decreases, in Petrus' revenues from its reserves, which may affect our ability to expend the necessary capital to replace our reserves or to maintain our production. To the extent that external sources of capital become limited, unavailable or available on onerous terms, our ability to make capital investments and maintain existing assets may be impaired, and our assets, liabilities, business, financial condition and results of operations may be affected materially and adversely as a result. In addition, the future development of the Corporation's petroleum properties may require additional financing and there are no assurances that such financing will be available or, if available, will be available upon acceptable terms. Alternatively, any available financing may be highly dilutive to existing shareholders. Failure to obtain any financing necessary for Petrus' capital expenditure plans may result in a delay in development or production on our properties.

Credit Facility Arrangements

The Petrus Credit Facilities and the amount authorized thereunder is dependent on the borrowing base determined by our lenders. We are required to comply with covenants under the Petrus Credit Facilities which may, in certain cases, include certain financial ratio tests, which from time to time either affect the availability, or price, of additional funding and in the event that we do not comply with these covenants, Petrus' access to capital could be restricted or repayment could be required. Events beyond the Corporation's control may contribute to a failure to comply with such covenants. Such a failure to comply with covenants could result in default under the Petrus Credit Facilities, which could result in the Corporation being required to repay amounts owing thereunder. The acceleration of our indebtedness under one agreement may permit acceleration of indebtedness under other agreements that contain cross default or cross-acceleration provisions. In addition, the Petrus Credit Facilities may impose operating and financial restrictions on us that could include restrictions on, the payment of dividends, repurchase or making of other distributions with respect to our securities, incurring of additional indebtedness, the provision of guarantees, the assumption of loans, making of capital expenditures, entering into of amalgamations, mergers, take-over bids or disposition of assets, among others**.**

Our lenders use Petrus' reserves, commodity prices, applicable discount rate and other factors, to periodically determine our borrowing base. Commodity prices continue to be depressed and have fallen dramatically since 2014. There remains a substantial amount of uncertainty as to when and if commodity prices will recover. Depressed commodity prices could reduce our borrowing base, reducing the funds available to Petrus under the Petrus Credit Facilities. This could result in the requirement to repay a portion, or all, of our indebtedness.

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

Issuance of Debt

From time to time, Petrus may enter into transactions to acquire assets or shares of other organizations. These transactions may be financed in whole or in part with additional debt, which may increase our debt levels above industry standards for oil and natural gas companies of similar size. Depending on future exploration and development plans, we may require additional debt financing that may not be available or, if available, may not be available on favourable terms. Neither Petrus' articles nor our by-laws limit the amount of indebtedness that we may incur. 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.

Hedging

From time to time, we may enter into agreements to receive fixed prices on 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, Petrus' hedging arrangements may expose us to the risk of financial loss in certain circumstances, including instances in which:

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

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

Availability of Drilling Equipment and Access

Our oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment (typically leased from third parties) in the particular areas where such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to Petrus and may delay our exploration and development activities.

Title to Assets

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 a defect in the chain of title will not arise. The actual interest of the Corporation in properties may accordingly vary from the Corporation's records. If a title defect does exist, it is possible that the Corporation may lose all or a portion of the properties to which the title defect relates, which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. There may be valid challenges to title or legislative changes, which affect the Corporation's title to the oil and natural gas properties the Corporation controls that could impair the Corporation's activities on them and result in a reduction of the revenue received by the Corporation.

Reserve Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and NGL reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth in this document are estimates only. Generally, estimates of economically recoverable oil and natural gas reserves and the future net cash flows from such estimated reserves are based upon a number of variable factors and assumptions, such as:

- historical production from the properties;
- production rates;
- ultimate reserve recovery;
- timing and amount of capital expenditures;
- marketability of oil and natural gas;
- royalty rates; and
- the assumed effects of regulation by governmental agencies and future operating costs (all of which may vary materially from actual results).

For those reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times may vary. Our actual production, revenues, taxes and development and operating expenditures with respect to our reserves will vary from estimates and such variations could be material.

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

In accordance with applicable securities laws, Petrus' independent reserves evaluator has used forecast prices and costs in estimating the reserves and future net cash flows as summarized herein. Actual future net cash flows will be affected by other factors, such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs.

Actual production and cash flows derived from our oil and natural gas reserves will vary from the estimates contained in the reserve evaluation, and such variations could be material. The reserve evaluation is based in part on the assumed success of activities we intend to undertake in future years. The reserves and estimated cash flows to be derived therefrom and contained in the reserve evaluation will be reduced to the extent that such activities do not achieve the level of success assumed in the reserve evaluation. The reserve evaluation is effective as of a specific effective date and, except as may be specifically stated, has not been updated and therefore does not reflect changes in our reserves since that date.

Insurance

Our involvement in the exploration for and development of oil and natural gas properties may result in liability for pollution, blow outs, leaks of sour natural gas, property damage, personal injury or other hazards. Although we maintain insurance in accordance with industry standards to address certain of these risks, such insurance has limitations on liability and may not be sufficient to cover the full extent of such liabilities. In addition, certain risks are not, in all circumstances, insurable or, in certain circumstances, we may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of any uninsured liabilities would reduce the funds available to Petrus. The occurrence of a significant event that we are not fully insured against, or the insolvency of the insurer of such event, may have a material adverse effect on our business, financial condition, results of operations and prospects.

Geopolitical Risks

Political events throughout the world that cause disruptions in the supply of oil continuously affect the marketability and price of oil and natural gas acquired or discovered by the Corporation. Conflicts, or conversely peaceful developments, arising outside of Canada have a significant impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and result in a reduction of our net production revenue.

In addition, Petrus' oil and natural gas properties, wells and facilities could be the subject of a terrorist attack. If any of our properties, wells or facilities are the subject of terrorist attack it may have a material adverse effect on our business, financial condition, results of operations and prospects. We do not have insurance to protect against the risk from terrorism.

Dilution

We may make future acquisitions or enter into financings or other transactions involving the issuance of our securities which may be dilutive.

Management of Growth

Petrus may be subject to growth related risks including capacity constraints and pressure on its 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.

Expiration of Licenses and Leases

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

Dividends

Petrus has not paid any dividends on the outstanding Common Shares. Payment of dividends in the future, if any, will be dependent on, among other things, our cash flow, results of operations, financial condition and the need for funds to finance ongoing operations and other considerations, as the Board of Directors considers relevant.

Litigation

In the normal course of the Corporation's operations, it 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, relating to personal injuries, including resulting from exposure to hazardous substances, property damage, property taxes, land

and access rights, environmental issues, including claims relating to contamination or natural resource damages and contract disputes. The outcome with respect to outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to the Corporation, and as a result, could have a material adverse effect on the Corporation's assets, liabilities, business, financial condition and results of operations. Even if the Corporation prevails in any such legal proceedings, the proceedings could be costly and time-consuming and may divert the attention of management and key personnel from business operations, which could have an adverse effect on the Corporation's financial condition.

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights in portions of western Canada. Petrus is 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.

Breach of Confidentiality

While discussing potential business relationships or other transactions with third parties, we may disclose confidential information relating to our business, operations or affairs. Although confidentiality agreements are 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 our business that such a breach of confidentiality may cause.

Income Taxes

Petrus files 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 the Corporation, 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 natural gas industry, such as the treatment of resource taxation or dividends, may in the future be changed or interpreted in a manner that adversely affects Petrus. 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.

Seasonality

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 our rigs and other heavy equipment, thereby reducing activity levels. In addition, 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. Seasonal factors and unexpected weather patterns may lead to declines in our exploration and production activity and corresponding decreases in the demand for our goods and services.

Third Party Credit Risk

We may be exposed to third party credit risk through our contractual arrangements with our current or future joint venture partners, marketers of our petroleum and natural gas production and other parties. In addition, we may be exposed to third party credit risk from operators of properties in which we have a working or royalty interest. In the event such entities fail to meet their contractual obligations, such failures may 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 affect a joint venture partner's willingness to participate in Petrus' ongoing capital program, potentially delaying the program and the results of such program until we find a suitable alternative partner. To the extent that any of such third parties go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency, it could result in Petrus being unable to collect all or portion of any money owing from such parties. Any of these factors could materially adversely affect our financial and operational results.

Conflicts of Interest

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

Reliance on Key Personnel

The Corporation's success depends in large measure on certain key personnel. The loss of the services of such key personnel may have a material adverse effect on our business, financial condition, results of operations and prospects. We do not have any key person insurance in effect. The contributions of the existing management team to the immediate and near term operations of Petrus 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.

Information Technology Systems and Cyber-Security

The Corporation has 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. The Corporation depends 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, the Corporation is subject to a variety of information technology and system risks as a part of its normal course operations, including potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach, and destruction or interruption of the Corporation’s information technology systems by third parties or insiders. Unauthorized access to these systems by employees or third parties could lead to corruption or exposure of confidential, fiduciary or proprietary information, interruption to communications or operations or disruption to our business activities or our competitive position. Further, disruption of critical information technology services, or breaches of information security, could have a negative effect on our performance and earnings, as well as on our reputation. The Corporation applies 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 the Corporation’s business, financial condition and results of operations.

Expansion into New Activities

The operations and expertise of our management is currently focused primarily on oil and natural gas production, exploration and development in the Western Canada Sedimentary Basin. In the future we may acquire or move into new industry related activities or new geographical areas, may acquire different energy related assets, and as a result may face unexpected risks or alternatively, significantly increase our exposure to one or more existing risk factors, which may in turn result in our future operational and financial conditions being adversely affected.

Forward-Looking Information May Prove Inaccurate

Shareholders and prospective investors are cautioned not to place undue reliance on our forward-looking information. By its nature, forward-looking information involves numerous assumptions, known and unknown risk and uncertainties, of both a general and specific nature, that could cause actual results to differ materially from those suggested by the forward-looking information or contribute to the possibility that predictions, forecasts or projections will prove to be materially inaccurate.

Additional information on the risks, assumption and uncertainties are found under the heading "*Special Note Regarding Forward-Looking Statements*" of this Annual Information Form.

LEGAL PROCEEDINGS

There are no legal proceedings involving claims for damages for which the potential exposure is more than 10% of our current assets to which we are or was a party or in respect of which any of our properties are or were subject during the year ended December 31, 2016, nor are there any such proceedings known to us to be contemplated.

During the year ended December 31, 2016 there were: (i) no penalties or sanctions imposed against us by a court relating to securities legislation or by a securities regulatory authority; (ii) no other penalties or sanctions imposed by a court or regulatory body against us that we believe would likely be considered important to a reasonable investor in making an investment decision; and (iii) no settlement agreements entered into by us with a court relating to securities legislation or with a securities regulatory authority.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Except as set forth under "*Agreements with NGP*", there were no material interests, direct or indirect, of directors and officers of Petrus, any shareholder who beneficially owns more than 10% of the Common Shares, or any known associate or affiliate of such persons in any transaction completed within three years before the date of this Annual Information Form, or in any proposed transaction which has materially affected or would materially affect Petrus. Brian Minnehan and Jeff Zlotky are current directors of Petrus and are principals of NGP. Joe Looke and Roy Aneed were principals of NGP during the time they each served as directors of Old Petrus.

There were no material interests, direct or indirect, of directors and officers of Petrus, any shareholder who beneficially owns more than 10% of the Common Shares, or any known associate or affiliate of such persons in any transaction completed within three years before the date of this Annual Information Form, or in any proposed transaction which has materially affected or would materially affect Petrus.

AUDITOR, TRANSFER AGENT AND REGISTRAR

Our auditor is Ernst & Young LLP, Chartered Professional Accountants. Ernst & Young LLP has been our auditor since November 25, 2015. Ernst & Young LLP were the auditors of Old Petrus from November 9, 2011 to February 2, 2016.

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

MATERIAL CONTRACTS

Other than the Petrus Credit Facilities, the Petrus Term Loan and contracts entered in the ordinary course of business, the only material contracts entered into by us within our most recently completed financial year, or before the most recently completed financial year but which are still material an in effect, are set forth below:

Agreements with NGP

Nomination Rights Agreement

Petrus entered into a nomination rights agreement (the "**Nomination Rights Agreement**") upon completion of the Arrangement in connection with the termination of the Old Petrus Shareholders' Agreement.

Such agreement provides that, as long as NGP owns: (i) at least 20% of the outstanding Common Shares (on a non-diluted basis), we will include two nominees of NGP; or (ii) at least 10% but not more than 20% of the outstanding Common Shares (on a non-diluted basis), we will include one nominee of NGP, among the nominees for election to the Board of Directors at each meeting of Shareholders at which directors are to be elected.

Additionally, such agreement provides that for a period of two years following the date of such agreement, we shall not do any of the following without the approval of NGP in its capacity as a shareholder:

(a) create, grant, issue, or modify any incentive security or any related plan or instrument; or

(b) enter into, modify or terminate any existing employment agreement, non competition agreement, or similar agreement with any executive officer.

The Nomination Rights Agreement shall terminate upon agreement between NGP and Petrus or upon NGP holding less than 10% of the Common Shares (on a non-diluted basis).

A copy of the Nomination Rights Agreement has been filed on our SEDAR profile at *www.sedar.com*.

Transfer Restriction Agreements

Management and director share transfer restriction agreements, as applicable, are outstanding among NGP, Petrus and each of Mr. Mr. Neil Korchinski, our President and Chief Executive Officer, Ms. Cheree Stephenson, our Vice President, Finance and Chief Financial Officer (the "**Common Share Transfer Restriction Agreements**") following completion of the Arrangement.

The Common Share Transfer Restriction Agreements restrict the transfer of an aggregate of 2,660,320 Common Shares (plus certain additional Common Shares as may be issued upon the exercise of Options, Old Petrus Options and Old Petrus Warrants, as the case may be, held by the parties, subject to certain conditions) unless such transfer is approved by NGP or is a transfer to a permitted transferee. The share transfer restrictions contained in the Common Share Transfer Restriction Agreements shall not apply in the case of a transaction involving a "fundamental change" of Petrus (as such term is defined in the Common Share Transfer Restriction Agreements).

The Common Share Transfer Restriction Agreements shall terminate on the earlier of: (i) three years from the date of the Common Share Transfer Restriction Agreements; (ii) a completion of a transaction giving rise to a "fundamental change"; (iii) the date of that NGP no longer owns or controls 5% of the Common Shares (on a non-diluted basis); or (iv) the date on which the Common Shares held by the parties to the Common Share Transfer Restriction Agreements are no longer subject to transfer restrictions.

Management Share Transfer Restriction Agreement

Under the management share transfer restriction agreement, the 185,000 Common Shares (plus certain additional Common Shares as may be issued upon the exercise of Options, Old Petrus Options and Old Petrus Warrants, as the case may be, held by the parties, subject to certain conditions) held by the management parties thereto will be released from the transfer restrictions contained therein in increments of 1/3 on the first, second and third anniversaries of the date of the applicable Common Share Transfer Restriction Agreement, subject to certain adjustments.

Registration Rights Agreement

The following is a description of certain provisions of our registration rights agreement (the "**Registration Rights Agreement**") dated February 2, 2016, pursuant to which we granted certain rights to NGP and to our officers at the time of entering into of the Registration Rights Agreement. The following description of certain provisions of the Registration Rights Agreement is a summary only, is not comprehensive and is qualified in its entirety by reference to the full text of the Registration Rights Agreement, a copy of which has been filed on our SEDAR profile at *www.sedar.com*.

Demand Rights

The Registration Rights Agreement provides that at any time after we become a reporting issuer in any province or territory of Canada, NGP has the right, subject to certain limitations, to request that we file all necessary documents, including a prospectus in Canada or, in certain circumstances, a registration statement in the United States, to distribute to the public all or any portion of the Registrable Securities (as defined below) held by NGP. We must use our commercially reasonable efforts to file a preliminary prospectus or registration statement, as applicable, within 90 days of receipt of a notice from NGP of exercise of such a demand right.

Pursuant to the Registration Rights Agreement, the other parties (other than Petrus) to the Registration Rights Agreement (the "**Other Holders**") shall be notified of NGP's demand request and each of the Other Holders and Petrus may elect to participate in such an offering (through an issuance of Common Shares from treasury in the case of Petrus). The rights of NGP to participate in a distribution or registration pursuant to the foregoing demand rights may be limited to the extent that the underwriter for the distribution or registration determines that market or other relevant factors require a limitation of the number of Registrable Securities to be sold by NGP. To the extent that the underwriter imposes such a limitation, NGP may participate to the exclusion of other participants.

Subject to certain exceptions, NGP shall not be entitled to demand more than three demand requests in total under the Registration Rights Agreement. Further, the Registrable Securities proposed to be distributed under an underwritten offering must have a fair market value of at least $5,000,000 or be all of NGP's remaining holdings of Registrable Securities.

Piggyback Rights

The Registration Rights Agreement provides that NGP and the Other Holders have the right, subject to certain limitations, to include some or all of the Registrable Securities held by them in any distribution of Registrable Securities (whether a distribution from treasury or from other securityholders) qualified for distribution under applicable securities laws by way of a prospectus in Canada or, in certain circumstances, by way of a registration statement in the United States.

The rights of NGP and the Other Holders to participate in a distribution or registration pursuant to the foregoing piggyback rights may be limited to the extent that the underwriter for the distribution or registration determines that market or other relevant factors require a limitation of the number of Registrable Securities to be sold by NGP and the Other Holders.

As long as NGP owns at least 10% of the equity interest in Petrus, we shall not grant any piggyback rights or similar rights to any person unless such rights are expressly made subject to the prior right of NGP and the Other Holders in the Registration Rights Agreement.

Additional Terms

We are responsible for all fees and expenses incurred in connection with the exercise by NGP of any of its rights under the Registration Rights Agreement other than, except in limited circumstances, the expenses of counsel or other advisors of NGP and the Other Holders. In addition, each of NGP and the Other Holders exercising its rights shall pay the underwriting discounts, commissions and similar fees and transfer taxes applicable to their respective Registrable Securities.

Pursuant to the Registration Rights Agreement, we are obliged to indemnify NGP and the Other Holders exercising its rights under the Registration Rights Agreement for losses arising out of any violation by Petrus of applicable securities laws, any untrue statement or alleged untrue statement of a material fact contained in any prospectus or registration statement of ours, or any omission or alleged omission to state therein a material fact required to be stated therein or necessary to make any statement therein not misleading (excluding any information provided by NGP or the Other Holders), and any breach by us of the Registration Rights Agreement. Pursuant to the Registration Rights Agreement, each of NGP and the Other Holders exercising its rights under the Registration Rights Agreement is obliged to severally indemnify Petrus for losses arising out of any untrue statement of material fact made by it contained in any prospectus or registration statement of ours, or any omission of a material fact required to be stated therein or necessary to make any statement therein not misleading.

The Registration Rights Agreement will terminate at such time as NGP no longer holds any Registrable Securities.

Under the Registration Rights Agreement, "**Registrable Securities**" means the Common Shares held by NGP and/or the Other Holders immediately prior to the date that NGP first becomes entitled to exercise demand rights pursuant to the Registration Rights Agreement; provided, however, that, in connection with any U.S. initial public offering or Canadian initial public offering, Registrable Securities shall be deemed to include all Common Shares held by NGP and/or the Other Holders at such time; *provided, further*, that a Registrable Security shall cease to be a Registrable Security upon the earlier of the time (a) a registration statement covering such Registrable Security has been declared effective by the U.S. Securities Act and such Registrable Security has been sold or disposed of pursuant to such effective registration statement, or (b) such Registrable Security has been disposed of pursuant to any section of Rule 144 (or any similar provision then in force) or Regulation S under the U.S. Securities Act.

INTERESTS OF EXPERTS

As of December 31, 2016, no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a report, valuation, statement or opinion described or included in a filing, or referred to in a filing, made under NI 51-102 by us during, or related to, our most recently completed financial year other than Sproule, our independent engineering evaluator, and Ernst & Young LLP, our independent auditor.

Reserve estimates contained in this Annual Information Form are derived from reserve reports prepared by Sproule. To our knowledge, no registered or beneficial interests, direct or indirect, in any securities or other property of Petrus or of one of our associates or affiliates (i) were held by Sproule when Sproule prepared the report, valuation, statement or opinion in question, or (ii) are to be received by Sproule. Sproule did not, nor is any director, officer or employee of Sproule expected to be elected, appointed or employed as a director, officer or employee of Petrus or of any associate or affiliate thereof.

Petrus' auditors are Ernst & Young LLP, Chartered Professional Accountants, who have prepared independent auditors' report**s** dated March 8, 2017 and March 22, 2016 and in respect of Old Petrus' financial statements as at December 31, 2015 and 2014 respectively**,** and for the years then ended and who reviewed the financial statements for the three and nine months ended September 30, 2016. Ernst & Young LLP has advised that they are independent with respect to Petrus within the meaning of the Rules of Professional Conduct of the Institute of Chartered Professional Accountants of Alberta.

As at the date hereof, the partners and associates of Burnet, Duckworth & Palmer LLP, as a group, owned, directly or indirectly, less than 1% of the outstanding Common Shares.

ADDITIONAL INFORMATION

Additional information relating to us can be found on our SEDAR profile at *www.sedar.com*. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of our securities and securities authorized for issuance under equity compensation plans will be contained in our information circular and proxy statement for our annual general meeting of shareholders to be held on May 18, 2017. Additional financial information is contained in our financial statements and the related management's discussion and analysis for the year ended December 31, 2016.

SCHEDULE "A"

MANDATE OF THE AUDIT COMMITTEE OF THE BOARD OF DIRECTORS

I. PURPOSE

The primary function of the audit committee (the "**Audit Committee**") of the board of directors (the "**Board of Directors**" or "**Board**") of Petrus Resources Ltd. ("**Petrus**" or the "**Corporation**") is to assist in fulfilling the Board's responsibilities by reviewing: (a) the financial reports and other financial information provided by Petrus to any governmental body or the public; (b) Petrus' systems of internal controls regarding finance, accounting, legal compliance and ethics that management and the Board have established; and (c) Petrus' auditing, accounting and financial reporting processes generally. Consistent with this function, the Audit Committee should endeavour to encourage continuous improvement of, and should endeavour to foster adherence to, the Corporation's policies, procedures and practices at all levels. In performing its duties, the external auditor of the Corporation is to report directly to the Audit Committee.

II. OBJECTIVES

The Audit Committee's primary objectives are:

1. to assist the Board to meet its responsibilities (especially for accountability) in respect of the preparation and disclosure of the financial statements of the Corporation and related matters;

2. to provide better communication between directors and external auditors;

3. to assist the Board's oversight of the auditor's qualifications and independence;

4. to assist the Board's oversight of the credibility, integrity and objectivity of financial reports;

5. to strengthen the role of the outside directors by facilitating discussions between directors on the Audit Committee, management and external auditors;

6. to assist the Board's oversight of the Corporation's compliance with legal and regulatory requirements; and

7. to review the risks that may affect Petrus and the risk management policies and procedures of the Corporation.

III. COMPOSITION

The Audit Committee shall be comprised of three or more directors as determined by the Board of Directors, none of whom are members of management of Petrus, except as otherwise permitted in National Instrument 52-110 ("**NI 52-110**"), all of whom are "independent" and "financially literate" (as such terms are defined in NI 52-110). Audit Committee members may enhance their familiarity with finance and accounting by participating in educational programs conducted by the Corporation or an outside consultant. In addition, at least one member of the Audit Committee must have accounting or related financial management expertise, as the Corporation's Board of Directors interprets such qualification in its business judgment.

The members of the Audit Committee shall be appointed by the Board of Directors by resolution and remain as members of the Audit Committee until their successors are duly appointed. Unless a Chair is elected by the full Board of Directors, the members of the Audit Committee may designate a Chair by majority vote of the full Audit Committee membership.

IV. MEETINGS

The Audit Committee shall meet at least four times annually, or more frequently as circumstances dictate. As part of its job to foster open communication, the Audit Committee should meet at least annually with management, internal auditors (if any) and the independent auditors to discuss any matters that the Audit Committee or each of these groups believe should be discussed privately. In addition, the Audit Committee or at least its Chair should meet with the independent auditors and management quarterly to review the Corporation's financial statements and MD&A consistent with Section V.4 below. The Audit Committee should also meet with management and independent auditors on an annual basis to review and discuss annual financial statements and the management's discussion and analysis of financial conditions and results of operations.

A quorum for meetings of the Audit Committee shall be a majority of its members, and the rules for calling, holding, conducting and adjourning meetings of the Audit Committee shall be the same as those governing the Board.

V. RESPONSIBILITIES AND DUTIES

To fulfill its responsibilities and duties, the Audit Committee shall endeavour to:

Documents/Reports Review

1. Review and, if deemed appropriate, update this Mandate, at least annually, as conditions dictate.

2. Review and recommend to the Board the organization's annual and interim financial statements, MD&A, earnings press releases and review any reports or other financial information submitted to any governmental body or the public, including any certification, report, opinion or review rendered by the independent auditors.

3. Review the reports to management prepared by the independent auditors and management's responses.

4. Review with financial management and the independent auditors the quarterly financial statements prior to their filing or prior to the release of earnings.

5. Review significant findings during the year, including the status of previous significant audit recommendations.

6. Periodically assess the adequacy of procedures for the review of corporate disclosure that is derived or extracted from the financial statements.

7. Periodically discuss guidelines and policies to govern the processes by which the Chief Executive Officer and senior management assess and manage the Corporation's exposure to risk.

8. Report to the Board any issues that arise with respect to the quality or integrity of the Corporation's financial statements, compliance with legal or regulatory requirements, performance and independence of the Corporation's auditors, or performance of the internal audit function.

9. Reviewing any inquiry or investigation by governmental or professional authorities respecting any independent audits carried out on the Corporation and any steps to deal with any such issues.

Independent Auditors

10. Recommend to the Board the external auditors to be nominated for appointment by the shareholders.

11. Approve the compensation of the external auditors.

12. On an annual basis, the Audit Committee should review and discuss with the auditors all significant relationships the auditors have with the Corporation to determine the auditors' independence.

13. Review and, as appropriate, resolve any material disagreements between management and the independent auditors and review, consider and make a recommendation to the Board regarding any proposed discharge of the auditors when circumstances warrant.

14. When there is to be a change in auditors, review the issues related to the change and the information to be included in the required notice to securities regulators of such change.

15. Periodically consult with the independent auditors, without the presence of management, about internal controls and the fullness and accuracy of the organization's financial statements.

16. Periodically assess the Corporation's internal controls, including Corporation's risk management processes.

17. Review the audit scope and plan of the independent auditor.

18. Oversee the work of the external auditors engaged for the purpose of preparing or issuing an auditor's report or performing other audit, review or attest services for Petrus.

19. Pre-approve the completion of any non-audit services by the external auditors and, with the assistance of the auditors, determine which non-audit services the external auditor is prohibited from providing. The Audit Committee may delegate to one or more members of the Audit Committee authority to pre-approve non-audit services in satisfaction of this requirement and if such delegation occurs, the pre-approval of non-audit services by the Audit Committee member to whom authority has been delegated must be presented to the Audit Committee at its first scheduled meeting following such pre-approval. The Audit Committee shall be entitled to adopt specific policies and procedures for the engagement of non-audit services if:

(a) the pre-approval policies and procedures are detailed as to the particular service;

(b) the Audit Committee is informed of each non-audit service; and

(c) the procedures do not include delegation of the Audit Committee's responsibilities to management.

The Audit Committee will satisfy the pre-approval requirement set forth in this paragraph if:

(a) the aggregate amount of all non-audit services that were not pre-approved is reasonably expected to constitute no more than 5% of the total amount of fees paid by Petrus and its subsidiary entities to the auditors during the fiscal year in which the services are provided;

(b) Petrus or a subsidiary entity, as the case may be, did not recognize the services as non-audit services at the time of the engagement; and

(c) the services are promptly brought to the attention of the Audit Committee and approved, prior to completion of the audit, by the Audit Committee or by one or more of its members to whom authority to grant such approvals has been delegated by the Audit Committee.

Financial Reporting Processes

20. In consultation with the independent auditors, annually review the organization's financial reporting processes and the quality and appropriateness of the Corporation's accounting principles as applied in its financial reporting.

21. Consider and approve, if appropriate, major changes to the Corporation's auditing and accounting principles and practices as suggested by the independent auditors or management.

22. Review risk management policies and procedures of Petrus (i.e. litigation and insurance).

Process Improvement

23. Request reporting to the Audit Committee by each of management and the independent auditors of any significant judgments made in the management's preparation of the financial statements and the view of each group as to appropriateness of such judgments.

24. Following completion of the annual audit, review separately with each of management and the independent auditors any significant difficulties encountered during the course of the audit, including any restrictions on the scope of work or access to required information.

25. Review any significant disagreements among management and the independent auditors in connection with the preparation of the financial statements.

26. Review with the independent auditors and management the extent to which changes or improvements in financial or accounting practices, as approved by the Audit Committee, have been implemented. (This review may be conducted at an appropriate time subsequent to implementation of changes or improvements, as decided by the Audit Committee.)

27. Conduct and authorize investigations into any matters brought to the Audit Committee's attention and within the Audit Committee's scope of responsibilities. The Audit Committee shall be empowered to retain and to approve compensation for any independent counsel and other professionals to assist in the conduct of any investigation.

28. Review the systems that identify and manage principal business risks.

29. Assist with the establishment of a procedure for:

(a) the receipt, retention and treatment of complaints received by the Corporation regarding accounting, internal accounting controls or auditing matters; and

(b) the confidential, anonymous submission by employees of Petrus of concerns regarding questionable accounting matters, auditing matters and matters set forth in Petrus' Code of Business Conduct and Ethics,

which procedure shall be set forth in a "Whistle Blower Policy" to be adopted by the Board in connection with such matters.

Ethical and Legal Compliance

30. Assist with the establishment of a Code of Business Conduct and Ethics and ensure that management has established a system to enforce same.

31. Review management's monitoring of the Corporation's compliance with the Code of Business Conduct and Ethics.

32. In consultation with the auditors, consider the review system established by management regarding the Corporation's financial statements, reports and other financial information disseminated to governmental organizations and the public in the context of the applicable legal requirements.

33. On at least an annual basis, review with the Corporation's auditors or counsel, as appropriate, any legal matters that could have a significant impact on the organization's financial statements, the Corporation's compliance with applicable laws and regulations and inquiries received from regulators or government agencies.

Other

34. Perform any other activities consistent with this Mandate, Petrus' by-laws and governing law, as the Audit Committee or the Board of Directors deems necessary or appropriate.

35. In connection with the performance of its responsibilities as set forth above, the Audit Committee shall have the authority to engage outside advisors and to pay outside auditors and advisors.

Standards of Liability

Nothing contained in this mandate is intended to expand applicable standards of liability under statutory, regulatory, common law or any other legal requirements for the Board or members of its Committees. The purposes and responsibilities outlined in this mandate and accompanying Board materials are meant to serve as guidelines rather than inflexible rules and the Board may adopt such additional procedures and standards as it deems necessary from time to time to fulfill its responsibilities.

SCHEDULE "B"

REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR (FORM 51-101 F2)

To the Board of Directors of Petrus Resources Ltd. (the "**Company**"):

1. We have evaluated the Company's reserves data as at December 31, 2016. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2016, estimated using forecast prices and costs.

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

   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).

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

4. The following table shows the net present value of future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated for the year ended December 31, 2016, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's management and Board of Directors:

			Net Present Value of Future Net Revenue Before Income Tax Expenses (10% Discount Rate)			
Independent Qualified Reserves Evaluator or Auditor	**Effective Date of Evaluation Report**	**Location of Reserves (Country)**	**Audited (M$)**	**Evaluated (M$)**	**Reviewed (M$)**	**Total (M$)**
Sproule Associates Limited	December 31, 2016	Canada	Nil	420,888	Nil	420,888

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

6. We have no responsibility to update our report referred to in paragraph 5 for events and circumstances occurring after the effective date of our report, entitled "*Evaluation of the P&NG Reserves of Petrus Resources Ltd. (as of December 31, 2016)*".

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

Executed as to our report referred to above:

Sproule Associates Limited
Calgary, Alberta Canada
March 8, 2017

(signed) by *"Paul B. Jung"*
Paul B. Jung, P. Eng.
Project Leader; Manager, Engineering

(signed) by *"Weldon Dueck"*
Weldon Dueck, P. Eng.
Senior Petroleum Engineer

(signed) by *"Miles Hughes"*
Miles Hughes, P. Eng.
Practice Manager, Strategic Advisory

(signed) by *"Ian Kirkland"*
Ian K. Kirkland, P. Geol.
Senior Petroleum Geologist

(signed) by *"Alec Kovaltchouk"*
Alec Kovaltchouk, P. Geo.
Vice President, Geosciences

(signed) by *"Cameron P. Six"*
Cameron P. Six, P. Eng.
President and Chief Executive Officer

SCHEDULE "C"

REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE (FORM 51-101 F3)

Management of Petrus Resources Ltd. ("**Petrus**") is responsible for the preparation and disclosure of information with respect to Petrus' oil and natural gas activities in accordance with securities regulatory requirements. This information includes reserves data.

An independent qualified reserves evaluator has evaluated and reviewed Petrus' reserves data. The report of the independent qualified reserves evaluator is presented in Schedule "B" to the Annual Information Form of Petrus for the year ended December 31, 2016 (the "**AIF**").

The reserves committee (the "**Reserves Committee**") of the board of directors of Petrus (the "**Board of Directors**") has:

- reviewed Petrus' procedures for providing information to the independent qualified reserves evaluator, Sproule Associates Limited ("**Sproule**");
- met with Sproule to determine whether any restrictions affected the ability of Sproule to report without reservation; and
- reviewed the reserves data with management and with Sproule.

The Reserves Committee has reviewed Petrus' procedures for assembling and reporting other information associated with oil and natural gas activities and has reviewed that information with management. The Board of Directors has, on the recommendation of the Reserves Committee, approved:

- the content and filing with securities regulatory authorities of Form 51-101F1, incorporated into the AIF, containing reserves data and other oil and natural gas information;
- the filing of Form 51-101F2, which is the report of Sproule on the reserves data; and
- the content and filing of this report.

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

(signed) "Neil Korchinski"	*(signed) "Cheree Stephenson"*
Neil Korchinski President & Chief Executive Officer	Cheree Stephenson Vice President, Finance & Chief Financial Officer
(signed) "Donald Gray"	*(signed) "Patrick Arnell"*
Donald Gray Director & Chairman of the Reserves Committee	Patrick Arnell Director

March 8, 2017

SCHEDULE "D"

MANDATE OF THE BOARD OF DIRECTORS

The Board of Directors (the "**Board**") of Petrus Resources Ltd. ("**Petrus**" or the "**Corporation**") is responsible for the stewardship of the Corporation. In discharging its responsibilities, each member of the Board will exercise the care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances and will act honestly and in good faith with a view to the best interests of Petrus. In general terms, the Board will endeavor to:

(a) define the principal objective(s) of the Corporation based upon the recommendations of the Chief Executive Officer of the Corporation (the "CEO") and others deemed appropriate for such purpose;

(b) monitor the management of the business and affairs of Petrus with the goal of achieving Petrus' principal objective(s) as defined by the Board;

(c) discharge the duties imposed on the Board by applicable laws; and

(d) for the purpose of carrying out the foregoing responsibilities, take all such actions as the Board deems necessary or appropriate.

Without limiting the generality of the foregoing, the Board will endeavor to perform the following duties:

(a) Strategic Operating, Capital Plans and Financing Plans

(a) require the CEO to present annually to the Board a strategic plan for Petrus' business, which plan must:

  (i) be designed to achieve Petrus' principal objectives;

  (ii) identify the principal strategic and operational opportunities and risk of Petrus' business; and

  (iii) be approved by the Board as a pre-condition to the implementation of such plans.

(b) review progress towards the achievement of the goals established in the strategic, operating and capital plans;

(c) review the principal risks of the Corporation's business identified by the CEO and review management's implementation of the appropriate systems to manage these risks;

(d) approve the annual operating and capital budgets and plans and subsequent revisions thereof;

(e) approve property acquisitions and dispositions in excess of $500,000;

(f) approve the establishment of credit facilities and borrowings;

(g) approve issuances of securities;

(b) Monitoring and Acting

(a) monitor Petrus' progress towards its goals, and to revise and alter its direction through management in light of changing circumstances;

(b) monitor overall human resource policies and procedures, including compensation and succession planning;

(c) appoint the officers of the Corporation and, as required, determine the terms of the officers' employment with Petrus;

(d) review the systems implemented by management and the Board which are designed to maintain or enhance the integrity of Petrus' internal control and management information systems;

(e) monitor the "good corporate citizenship" of Petrus, including compliance by Petrus with all applicable environmental laws;

(f) in consultation with the CEO, establish the ethical standards to be observed by all officers, employees and consultants of Petrus and use reasonable efforts to ensure that a process is in place to monitor compliance with those standards;

(g) require that the CEO institute and monitor processes and systems designed to ensure compliance with applicable laws by Petrus and its officers and employees;

(h) approve all matters relating to a takeover bid of Petrus;

(c) Compliance Reporting and Corporate Communications

(a) review the procedures implemented by Management and the Board which are designed to ensure that the financial performance of Petrus is properly reported to shareholders, other security holders and regulators on a timely and regular basis;

(b) recommend to shareholders of Petrus a firm of Chartered Professional accountants to be appointed as Petrus' auditors;

(c) review the procedures designed and implemented by management and the independent auditors to ensure that the financial results are reported fairly and in accordance with generally accepted accounting principles;

(d) review the procedures implemented by Management and the Board which are designed to ensure the timely reporting of any other developments that have a significant and material impact on the value of Petrus;

(e) review, consider and where required, approve, disclosure required under National Instrument 51 101;

(f) report annually to shareholders on the Board's stewardship for the preceding year with respect to the disclosure requirements set forth in National Instrument 51 102; and

(g) where required, approve any policy designed to enable Petrus to communicate effectively with its shareholders and the public generally.

(d) Governance

(a) in consultation with the Chair of the Board, develop a position description for the Chair of the Board;

(b) facilitate the continuity, effectiveness and independence of the Board by, amongst other things:

(i) selecting nominees for election to the Board;

(ii) appointing a Chair of the Board who is not a member of management or, failing that, ensuing that an independent "lead director" is appointed;

(iii) appointing from amongst the directors an audit committee and such other committees of the Board as the Board deems appropriate;

(iv) defining the mandate or terms of reference of each committee of the Board;

(v) ensuring that processes are in place and are utilized to assess the effectiveness of the Chair of the Board, the Board as a whole, each committee of the Board and each director;

(vi) establishing a system to enable any director to engage an outside adviser at the expense of Petrus; and

(vii) review annually the adequacy and form of the compensation of directors.

(e) Delegation and Composition

(a) the Board may delegate its duties to and receive reports and recommendations from any committee of the Board.

(b) a majority of Board members should be "independent" Directors as such term is defined in National Instrument 58-101;

(c) on at least an annual basis, the Board shall conduct an analysis and make a positive affirmation as to the "independence" of a majority of its Board members; and

(d) members should have or obtain sufficient knowledge of Petrus and the oil and gas business to assist in providing advice and counsel on relevant issues.

(f) Meetings

(a) the Board shall meet at least four times per year and/or as deemed appropriate by the Board Chair;

(b) minutes of each meeting shall be prepared by the Corporate Secretary of the Corporation;

(c) the CEO may be present at all meetings of the Board subject to being excused from all in camera sessions of independent directors or where otherwise required for conflict or good governance purposes; and

(d) Vice-Presidents and such other staff as appropriate to provide information to the Board shall attend meetings at the invitation of the Board.

(g) Reporting / Authority

(a) following each meeting, the Corporate Secretary will promptly provide draft copies of the minutes of the meeting;

(b) supporting schedules and information reviewed by the Board at any meeting shall be available for examination by any director upon request to the CEO;

(c) the Board shall have the authority to review any corporate report or material and to investigate activity of the Corporation and to request any employees to cooperate as requested by the Board; and

(d) the Board may retain persons having special expertise and/or obtain independent professional advice to assist in fulfilling its responsibilities at the expense of Petrus.

(h) Standards of Liability

Nothing contained in this mandate is intended to expand applicable standards of liability under statutory, regulatory, common law or any other legal requirements for the Board or members of its Committees. The purposes and responsibilities outlined in this mandate and accompanying Board materials are meant to serve as guidelines rather than inflexible rules and the Board may adopt such additional procedures and standards as it deems necessary from time to time to fulfill its responsibilities.