WHITECAP RESOURCES INC

2016 Annual Information Form

March 6, 2017

TABLE OF CONTENTS

GLOSSARY OF TERMS

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

Entities

Bashaw means Bashaw Oil Ltd.

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

Beaumont means Beaumont Energy Inc.

Forge means Forge Petroleum Corp.

Invicta means Invicta Energy Corp.

Home Quarter means Home Quarter Resources Ltd.

Shareholders means holders of our Common Shares.

Spitfire means Spitfire Energy Inc.

Trident means Trident Limited Partnership.

Whitecap, **we**, **us, our** or the **Corporation** means Whitecap Resources Inc., and where the context requires, also means our controlled entities on a consolidated basis.

Independent Engineering

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

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.

McDaniel means McDaniel & Associates Consultants Ltd., independent petroleum consultants of Calgary, Alberta.

McDaniel Report means the report prepared by McDaniel dated February 16, 2017 evaluating the crude oil, natural gas, natural gas liquids and sulphur reserves attributable to all of our oil and natural gas assets as at December 31, 2016.

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

NSAI means Netherland, Sewell & Associates, Inc., worldwide petroleum consultants.

Trident Report means the report prepared by NSAI dated February 3, 2017 evaluating the crude oil, natural gas and natural gas liquids reserves attributable to the oil and natural gas assets of Trident as at December 31, 2016.

Share and Loan Capital

Common Shares means our common shares, as presently constituted.

Credit Facility means collectively our extendible revolving credit facility and term loan facility with a syndicate of lenders, all as more particularly described under the heading "*Description of our Capital Structure – Credit Facility*".

Senior Secured Notes means our senior secured notes as more particularly described under the heading "*Description of our Capital Structure – Senior Secured Notes*".

ABBREVIATIONS

Oil and Natural Gas Liquids

Bbl	barrel
Bbls	barrels
Bbls/d	barrels per day
Mbbls	thousand barrels
MMbbls	million barrels
Mstb	thousand stock tank barrels of oil
NGLs	natural gas liquids

Natural Gas

Mcf	thousand cubic feet
MMcf	million cubic feet
Bcf	billion cubic feet
Mcf/d	thousand cubic feet per day
MMcf/d	million cubic feet per day
MMbtu	million British Thermal Units
GJ	gigajoule

Other

AECO	the natural gas storage facility located at Suffield, Alberta, connected to TransCanada's Alberta System
API	American Petroleum Institute
°API	an indication of the specific gravity of crude oil measured on the API gravity scale
BOE or Boe	barrel or barrels of oil equivalent, using the conversion factor of 6 Mcf of natural gas being equivalent to one barrel of oil
Boe/d	barrels of oil equivalent per day
$Cdn	Canadian dollars
m^3	cubic metres
MMBoe	million barrels of oil equivalent
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for the crude oil standard grade
$000s	thousands of dollars

CONVERSIONS

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

To Convert From	To	Multiply By
Mcf	cubic metres	28.317
cubic metres	cubic feet	35.315
Bbls	cubic metres	0.159
cubic metres	Bbls	6.289
feet	Metres	0.305
metres	Feet	3.281
miles	Kilometres	1.609
kilometres	Miles	0.621
acres	Hectares	0.405
hectares	Acres	2.471
gigajoules	MMbtu	0.950
MMbtu	Gigajoules	1.0526

CONVENTIONS

Certain terms used herein are defined in the "*Glossary of Terms*". Certain other terms used herein but not defined herein are defined in NI 51-101 and CSA 51-324 and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101 and CSA 51-324. Unless otherwise indicated, references herein to "$" or "dollars" are to Canadian dollars. All financial information herein has been presented in Canadian dollars in accordance with generally accepted accounting principles in Canada.

BARREL OF OIL EQUIVALENCY

The term "Boe" may be misleading, particularly if used in isolation. A Boe conversion ratio of six thousand cubic feet of natural gas to barrels of oil (6 Mcf: 1 Bbl) is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. **Given the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6 Mcf: 1 Bbl, utilizing a conversion ratio at 6 Mcf: 1 Bbl may be misleading as an indication of value**.

NON-GAAP MEASURES

Within this Annual Information Form, references are made to terms commonly used in the oil and natural gas industry. The term "operating netback" in this Annual Information Form is not a recognized measure under generally accepted accounting principles in Canada. We use "operating netback" as a key performance indicator and it is used by us in operational and capital allocation decisions. It is determined by deducting royalties and operating expenses from petroleum and natural gas revenue. Readers are cautioned; however, that this measure should not be construed as an alternative to net earnings determined in accordance with generally accepted accounting principles in Canada as an indication of our performance.

FORWARD-LOOKING INFORMATION AND STATEMENTS

This Annual Information Form, including documents incorporated by reference herein, contains forward-looking information and statements (collectively, "**forward-looking statements**"). These forward-looking statements relate to future events or our future performance. All information and statements other than statements of historical fact contained in this Annual Information Form are forward-looking statements. Such forward-looking statements may be identified by looking for words such as "approximately", "may", "believe", "measure", "stability", "depends", "expects", "will", "intends", "should", "could", "plan", "budget", "predict", "potential", "projects", "anticipates", "forecasts", "estimates", "objective", "ongoing", "continues", "sustainability" or similar words or the negative thereof or other comparable terminology. In addition, there are forward-looking statements in this Annual Information Form under the headings: "*General Development of Our Business – Recent Developments*" with respect to our projected capital program; "*General Description of Our Business – Stated Business Objectives and Strategy*" as to our business plan and strategy; "*General Description of Our Business – Cyclical and Seasonal Impact of Industry*" as to the impact of our price risk management programs; "*General Description of Our Business – Environmental Policies*" with respect to our expectations regarding abandonment and reclamation costs; "*General Development of Our Business – Renegotiation or Termination of Contracts"* as to our expectations relating to the effect of the renegotiation or termination of our contracts or subcontracts in the remainder of 2017; "*Statement of Reserves Data and Other Oil and Natural Gas Information – Disclosure of Reserves Data*" as to our reserves and future net revenue from our reserves, income taxes and pricing, exchange and inflation rates; "*Statement of Reserves Data and Other Oil and Natural Gas Information – Additional Information Relating to Reserves Data*" as to the development of our proved undeveloped reserves and probable undeveloped reserves, abandonment and reclamation obligations, future developments costs, our plans to fund future development costs, anticipated drilling activity for 2017 and anticipated funding costs; "*Statement of Reserves Data and Other Oil and Natural Gas Information – Other Oil and Natural Gas Information*" as to our exploration and development focus, plans and opportunities, anticipated land expiries, hedging and marketing policies, tax horizon and future production; and "*Dividend Policy*" as to our dividend policy and the future payment of dividends.

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

- waterflood and alkaline surfactant polymer ("**ASP**") flood implementation opportunities and the results therefrom;
- recovery factors;
- well completions and the timing thereof;
- the performance characteristics of our oil and natural gas properties;
- expectation of future production rates, volumes and product mixes;
- projections of market prices and costs, and exchange and inflation rates;
- expectations regarding our ability to raise capital and to continually add to reserves through acquisitions, development and optimization;
- treatment under governmental regulatory regimes and tax laws;
- productive capacity of wells, anticipated or expected production rates and anticipated dates of commencement of production and timing of results therefrom;
- fluctuations in depletion, depreciation and accretion rates;
- changes in regulatory regimes and the effects of such changes; and
- our business plans and strategy.

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

Forward-looking statements are subject to risks, uncertainties and assumptions, including those discussed below and elsewhere in this Annual Information Form. Although we believe that the expectations represented in such forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. Some of the risks which could affect future results and could cause results to differ materially from those expressed in the forward-looking statements contained herein include the following:

- volatility in foreign exchange rates;
- depressed market prices of oil and natural gas;
- fluctuation in the supply and demand for oil and natural gas;
- operational risks and liabilities inherent in oil and natural gas operations;
- uncertainties associated with estimating oil and natural gas reserves;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- incorrect assessments of the value of acquisitions;
- geological, technical, drilling and processing problems;
- fluctuation in foreign exchange or interest rates;
- stock market volatility;
- environmental risks;
- the inability to access sufficient capital from internal and external sources;
- changes in general economic, market and business conditions;
- uncertainties and changes in royalty regimes;
- the accuracy of oil and gas reserves estimates and estimated production levels as they are affected by exploration and development drilling and estimated decline rates;
- the uncertainties in regard to the timing of our exploration and development program;
- fluctuations in the costs of borrowing;
- political or economic developments;
- ability to obtain regulatory and other third party approvals;
- the occurrence of unexpected events;
- the results of litigation or regulatory proceedings that may be brought against us;
- changes in income tax laws or changes in tax laws and incentive programs relating to the oil and gas industry;
- cyber-security issues; and
- the other factors discussed under "*Risk Factors*".

With respect to forward-looking statements contained in this Annual Information Form, we have made assumptions regarding, among other things: commodity prices and royalty regimes; availability of skilled labour; timing and amount of capital expenditures; future exchange rates; the price of oil and natural gas; the impact of increasing competition; conditions in general economic and financial markets; access to capital; availability of drilling and related equipment; effects of regulation by governmental agencies; royalty rates; and future operating costs.

We have included the above summary of assumptions and risks related to forward-looking statements provided in this Annual Information Form in order to provide investors with a more complete perspective on our current and future operations and such information may not be appropriate for other purposes.

You are further cautioned that the preparation of financial statements in accordance with generally accepted accounting principles in Canada requires management to make certain judgments and estimates that affect the reported amounts of assets, liabilities, revenues and expenses. Estimating reserves is also critical to several accounting estimates and requires judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change, having either a negative or positive effect on net earnings as further information becomes available and as the economic environment changes. **The information contained in this Annual Information Form, including the documents incorporated by reference herein, identifies additional factors that could affect our operating results and performance. We urge you to carefully consider those factors.**

The forward-looking statements contained herein are expressly qualified in their entirety by this cautionary statement. The forward-looking statements included in this Annual Information Form are made as of the date of this Annual Information Form and we undertake no obligation to publicly update such forward-looking statements to reflect new information, subsequent events or otherwise unless required by applicable securities laws.

WHITECAP RESOURCES INC.

General

We are the resulting entity following the completion of the reverse takeover of Spitfire and subsequent amalgamation with Spitfire on July 1, 2010 to form "Whitecap Resources Inc."

Spitfire was incorporated under the *Business Corporations Act* (Alberta) on August 30, 2001. On November 6, 2001, Spitfire amended and restated its articles to change its authorized share structure to include an unlimited number of common shares and an unlimited number of preferred shares. On March 31, 2004, Spitfire amalgamated pursuant to the *Business Corporations Act* (Alberta) with its wholly-owned subsidiary, Cashel Resources Inc. to form the amalgamated corporation, Spitfire Energy Ltd. On April 1, 2005, Spitfire purchased all of the issued and outstanding shares of, and then amalgamated with a private oil and gas company, Spitfire Exploration Ltd. pursuant to the *Business Corporations Act* (Alberta) to form Spitfire.

We were incorporated under the *Business Corporations Act* (Alberta) on June 3, 2008 as "1405340 Alberta Ltd.". On September 2, 2008, we amended our articles to change our name from 1405340 Alberta Ltd. to "Whitecap Resources Inc." and we commenced operations on September 17, 2009.

On October 15, 2010, we filed articles of amendment to effect a consolidation of our Common Shares on a basis of 10 pre-consolidated shares for every 1 Common Share. The consolidation was approved by our Shareholders at our annual general and special meeting held on September 14, 2010.

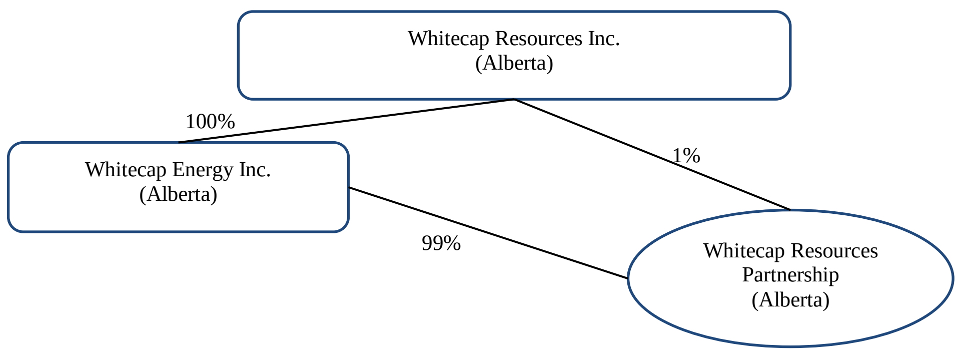
We have completed a number of corporate acquisitions since we commenced operations following which we have amalgamated the resulting subsidiary into Whitecap. We filed articles of amalgamation and amalgamated with the following acquired subsidiaries:

Date of Amalgamation	Name of Acquired Subsidiary
July 1, 2010	Spitfire
July 30, 2010	Onyx 2006 Inc.

Date of Amalgamation	Name of Acquired Subsidiary
April 20, 2011	Spry Energy Ltd.
February 10, 2012	Compass Petroleum Ltd.
April 23, 2012	Midway Energy Ltd.
April 30, 2013	Invicta
January 6, 2014	Home Quarter
October 1, 2014	Forge
October 1, 2014	Bashaw
January 1, 2015	1808039 Alberta Ltd.
May 1, 2015	Beaumont

Following the closing of a corporate acquisition in June of 2014, two private companies became our wholly-owned subsidiaries, one of which was renamed "Whitecap Energy Inc." and the other, 1808039 Alberta Ltd., was amalgamated into us on January 1, 2015. On July 21, 2014, we and our subsidiary Whitecap Energy Inc. became the two partners of Whitecap Resources Partnership, a general partnership formed pursuant to the laws of Alberta which holds a portion of our oil and gas assets. See "*General Development of Our Business – Developments in 2014*".

Our corporate structure is currently as follows:



Our head office is located at Suite 3800, 525 - 8th Avenue S.W., Calgary, Alberta, T2P 1G1 and our registered office is located at Suite 2400, 525 - 8th Avenue S.W., Calgary, Alberta, T2P 1G1.

GENERAL DEVELOPMENT OF OUR BUSINESS

History and Development

Since our inception, we have grown from a junior, privately held, oil and gas company to a publicly traded, oil-weighted growth company that pays a monthly cash dividend to our Shareholders.

The following provides a summary of how our business has developed over the last three years.

Developments in 2014

On January 6, 2014 we completed the acquisition of all of the issued and outstanding shares of Home Quarter in exchange for the issuance of 27,534,255 Common Shares and assumed Home Quarter's $3.0 million working capital surplus. For further information with respect to the acquisition of Home Quarter, see our business acquisition report relating to the acquisition which is available on our SEDAR profile at *www.sedar.com*.

On May 1, 2014 we completed an acquisition of certain light oil assets focused primarily in our Pembina Cardium/west central core area, as well as at Boundary Lake in northeast British Columbia for consideration of $683.0 million net of customary closing adjustments and proceeds of the subsequent disposition of certain Nisku natural gas production and related facilities which formed part of the assets acquired on May 1, 2014. The proceeds from the disposition were approximately $113.0 million. A portion of the purchase price of the assets was funded from the net proceeds of a bought deal public offering of 44,643,000 subscription receipts at a price of $11.20 per subscription receipt for aggregate gross proceeds of $500 million. The offering closed on April 8, 2014 and the subscription receipts were converted into Common Shares on May 1, 2014 contemporaneously with the closing of the acquisition. For further information with respect to the acquisition of these assets, see our business acquisition report relating to the acquisition which is available on our SEDAR profile at *www.sedar.com*.

On May 1, 2014 we increased the borrowing base of our Credit Facility to $1 billion from $600 million.

On June 26, 2014 we completed the acquisition of all of the issued and outstanding securities of two affiliated private companies for an aggregate purchase price of $107.1 million in cash. Following the closing of the acquisition one of the private companies was renamed "Whitecap Energy Inc." and the other was subsequently amalgamated into us on January 1, 2015. As part of the acquisition we acquired a 10 percent equity interest in Trident.

On July 21, 2014 we formed Whitecap Resources Partnership with Whitecap Energy Inc. and contributed certain of our oil and gas assets into the partnership. See "*Whitecap Resources Inc. – General*".

On July 31, 2014, we closed the disposition of $42.0 million in non-core assets in Southwest Alberta for cash consideration of $39.1 million and $4.6 million in undeveloped lands and facilities in northwest Alberta.

On October 1, 2014 we completed the acquisition of a controlling interest in the Nisku light sweet oil pool at Elnora, Alberta. The acquisition was comprised of a property acquisition and the acquisition of Forge and Bashaw. The aggregate purchase price of the acquisition was $277.2 million, which is net of customary closing adjustments. The acquisition was partially funded from the net proceeds of a bought deal public offering of 7,553,000 subscription receipts at a price of $16.55 per subscription receipt for gross proceeds of $125 million. The offering closed on September 11, 2014 and the subscription receipts were converted into Common Shares on October 1, 2014 contemporaneously with the closing of the acquisition. Subsequently, on October 17, 2014 we consolidated the remaining working interest in this pool at Elnora, Alberta through a property acquisition for cash consideration of $53.2 million.

On October 10, 2014 we completed the disposition of non-core assets located in Southwest Saskatchewan for cash consideration of $57.3 million.

On November 12, 2014 we completed the disposition of non-core assets we acquired as part of the Forge acquisition for proceeds of $30.5 million.

Developments in 2015

On March 3, 2015 we increased the borrowing base of our Credit Facility to $1.2 billion from $1.0 billion.

On May 1, 2015 we completed the acquisition of all of the issued and outstanding shares of Beaumont for consideration consisting of approximately $7.3 million in cash and 36.3 million Common Shares. We also assumed Beaumont's net debt. The cash portion of the consideration was funded from the net proceeds of a bought deal public offering of 8,149,000 subscription receipts at a price of $13.50 per subscription receipt for aggregate gross proceeds of approximately $110 million. The offering closed on April 9, 2015 and the subscription receipts were converted into Common Shares on May 1, 2015 contemporaneously with the closing of the acquisition.

On July 14, 2015 we appointed Mr. Daryl H. Gilbert to our Board of Directors.

Developments in 2016

We reduced our monthly dividend by 40% to $0.0375 per Common Share ($0.45 per Common Share annually) commencing with the February 2016 dividend.

On February 11, 2016, we disposed of certain production facilities to a third party for $70.0 million. Pursuant to the agreement, we will operate the facilities and will pay the purchaser an annual tariff fee for the life of the agreement and will retain all third party processing revenues generated. We have the option to repurchase the facilities at any time.

On March 15, 2016, we completed a bought deal public offering of 13,770,000 Common Shares at a price of $6.90 per Common Share for gross proceeds of $95.0 million.

We reduced our monthly dividend by 38% to $0.0233 per Common Share ($0.28 per Common Share annually) commencing with the April 2016 dividend.

On June 23, 2016, we completed an acquisition of oil assets in southwest Saskatchewan for cash consideration of $595 million, net of customary closing adjustments. The assets are located in southwest Saskatchewan and add 11,600 boe/d (98% oil) of low decline production and include significant facility infrastructure for future growth. The asset acquisition was partially funded from the net proceeds of a bought deal public offering of 51,087,000 subscription receipts at a price of $9.20 per subscription receipts for gross proceeds of $470 million. The offering closed on May 30, 2016 and the subscription receipts were converted into Common Shares on June 23, 2016 contemporaneously with closing of the acquisition.

In November 2016, our Board of Directors set our 2017 capital program to $300 million.

Recent Developments

On January 5, 2017, we issued $200 million Senior Secured Notes which have an annual coupon rate of 3.46% and mature on January 5, 2022. The notes were issued by way of a private placement, pursuant to a note purchase and private shelf agreement, and rank equally with our obligations under our Credit Facility. Proceeds from the notes were used to temporarily repay a portion of our outstanding bank debt.

Significant Acquisitions

We did not complete any significant acquisitions during our most recently completed financial year.

GENERAL DESCRIPTION OF OUR BUSINESS

Stated Business Objectives and Strategy

Our business plan is to deliver profitable growth to our Shareholders over the long term under varying business conditions. Since inception we have executed our business plan by pursuing strategic acquisitions and carrying out development programs focusing on our core properties in West Central Alberta, Southwest Saskatchewan, Northwest Alberta and British Columbia, and West Central Saskatchewan. See "*Statement of Reserves Data and Other Oil and Natural Gas Information – Other Oil and Natural Gas Information – Principal Properties*". Once a property has been acquired, we pursue optimization and ongoing development and expansion opportunities.

We are focused on providing monthly dividends and per share growth on our existing assets enhanced by acquisitions.

The key attributes to our dividend growth strategy are as follows:

- provide dividends and per share growth in production, reserves and cash flow;
- conservative payout ratio and strong balance sheet;
- strong capital efficiencies in concentrated areas;
- predictable and stable production base;
- large light oil development drilling inventory; and
- disciplined and value focused management team.

Cyclical and Seasonal Impact of Industry

Our operational results and financial condition are dependent on the prices received for our oil and natural gas production. Oil and natural gas prices have fluctuated widely during recent years and over the past year have slowly increased from the sharp decline experienced in 2015 and the first quarter of 2016. Such prices are determined by supply and demand factors, including weather and general economic conditions, as well as conditions in other oil and natural gas regions. Any decline in oil and natural gas prices could have an adverse effect on our financial condition. We mitigate such price risk through closely monitoring the various commodity markets and establishing price risk management programs, as deemed necessary and through maintaining financial flexibility. Additionally, we continually review our capital program and implement initiatives to adapt to such price changes. See "*Risk Factors – Prices, Markets and Marketing*", "*Risk Factors – Hedging*" and *"Risk Factors – Weakness in the Oil and Gas Industry"*.

Ongoing Acquisition and Disposition Activities

Potential Acquisitions

We evaluate potential acquisitions of all types of oil and natural gas and other energy related assets as part of our on-going asset portfolio management program. We are normally in the process of evaluating several potential acquisitions at any one time which individually or together could be material and it is in the normal course of our business to routinely make offers on properties or acquisitions that fit within our business objectives.

Potential Dispositions

We evaluate potential dispositions of our oil and natural gas assets as part of our ongoing asset portfolio management program. In addition, we evaluate potential farm-out opportunities with other industry participants in respect of our oil and natural gas assets in circumstances where we believe it is prudent to do so based on, among other things, our capital program, development plan timelines and the risk profile of such assets. We are normally in the process of evaluating several potential dispositions of our assets and farm-out opportunities at any one time, which individually or together could be material.

Environment Policies

We are committed to managing and operating in a safe, efficient, environmentally responsible manner in association with our industry partners and are committed to continually improving our environmental, health, safety and social performance. To fulfill this commitment, our operating practices and procedures are consistent with the requirements established for the oil and gas industry. Key environmental considerations include air quality and climate change, water conservation, spill management, waste management plans, lease and right-of-way management, natural and historic resource protection, and liability management (including site assessment and remediation). These practices and procedures apply to our employees and we monitor all activities and make reasonable efforts to ensure that companies who provide services to us will operate in a manner consistent with our environmental policy.

We believe that we meet all existing environmental standards and regulations and include sufficient amounts in our capital expenditure budget to continue to meet current environmental protection requirements. These requirements apply to all operators in the oil and gas industry; therefore it is not anticipated that our competitive position within the industry will be adversely affected by changes in applicable legislation. We have internal procedures designed to ensure that detailed due diligence reviews to assess environmental liabilities and regulatory compliance are completed prior to proceeding with new acquisitions and developments.

Our environmental management plan and operating guidelines focus on minimizing the environmental impact of our operations while meeting regulatory requirements and corporate standards. Our environmental program is monitored by our health, safety and environmental committee and includes: an internal environmental compliance audit and inspection program; a suspended well inspection program to support future development or eventual abandonment; appropriate reclamation and decommissioning standards for wells and facilities ready for abandonment; an effective surface reclamation program; a groundwater monitoring program; a spill prevention, response and clean-up program; a fugitive emission survey and repair program; and an environmental liability assessment program.

We expect to incur abandonment and reclamation costs as existing oil and gas properties are abandoned. In 2016, expenditures for normal compliance with environmental regulations as well as expenditures for above normal compliance were not material.

Renegotiation or Termination of Contracts

As at the date hereof, we do not anticipate that any aspect of our business will be materially affected in the remainder of 2017 by the renegotiation or termination of contracts or subcontracts other than with respect to our Credit Facility which has an annual renewal date in April of 2017. See "*Risk Factors – Credit Facility Arrangements*".

Competitive Conditions

We are a member of the petroleum industry, which is highly competitive at all levels. We compete with other companies for all of our business inputs, including exploration and development prospects, access to commodity markets, acquisition opportunities, available capital and staffing. See "*Risk Factors – Competition*".

We strive to be competitive by maintaining financial flexibility and by utilizing current technologies to enhance optimization, development and operational activities.

Human Resources

At December 31, 2016, we employed 160 full-time employees, including 102 office and 58 field employees.

STATEMENT OF RESERVES DATA AND OTHER OIL AND NATURAL GAS INFORMATION

The statement of reserves data and other oil and natural gas information set forth below is derived from the McDaniel Report dated February 16, 2017 and effective as of December 31, 2016 and does not include our share of Trident's oil and natural gas reserves and future net revenue. In certain of the tables below, we have added additional notes disclosing our share of Trident's oil and natural gas reserves and future net revenue. This disclosure has been made separately from our own reserves data and other oil and gas information as we have no direct right or entitlement to the reserves and future net revenue of Trident. Readers are cautioned that our interest in Trident may be reduced in various circumstances. All reserves data and other oil and natural gas information with respect to our interest in Trident set forth below is dated February 3, 2017 and effective as of December 31, 2016.

The Report of Management and Directors on Oil and Gas Disclosure in Form 51-101F3 (only with respect to the McDaniel Report) and the Reports on Reserves Data by Independent Qualified Reserves Evaluators in Form 51-101F2 are attached as Appendices A and B to this Annual Information Form.

Disclosure of Reserves Data

The reserves data set forth below is based upon evaluations by McDaniel and NSAI with an effective date of December 31, 2016 as contained in the McDaniel Report and Trident Report. The reserves data summarizes the crude oil, natural gas liquids and natural gas reserves and the net present values of future net revenue for these reserves using forecast prices and costs, not including the impact of any price risk management activities.

The McDaniel Report and Trident Report have both been prepared in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101 and CSA 51-324. We engaged McDaniel to provide an evaluation of our proved and proved plus probable reserves and no attempt was made to evaluate possible reserves. The Trident Report was prepared for the board of directors of Trident. We did not participate in or consult with NSAI in connection with the preparation of the Trident Report. Accordingly, we have not provided a

Report of Management and Directors on Oil and Gas Disclosure in Form 51-101F3 with respect to the Trident Report.

All of the reserves specified in the McDaniel Report and the Trident Report are in Canada and, specifically, in the Provinces of Alberta, Saskatchewan and British Columbia.

We determined the future net revenue and present value of future net revenue after income taxes by utilizing McDaniel'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 gas properties reflects the tax burden of our properties on a stand-alone basis. It does not provide an estimate of the value of us as a business entity, which may be significantly different. Our consolidated financial statements for the year ended December 31, 2016 should be consulted for additional information regarding our taxes.

As a limited partnership Trident is not subject to taxation at the partnership level so future net revenue after income taxes are equal to future net revenue before income taxes.

Future net revenue is 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. The estimated future net revenue contained in the following tables does not necessarily represent the fair market value of our reserves. There is no assurance that the forecast price and cost assumptions contained in the McDaniel Report and the Trident Report will be attained and variations could be material. Other assumptions and qualifications relating to costs and other matters are summarized in the notes to or following the tables below. Readers should review the definitions and information contained in "*Definitions and Notes to Reserves Data Tables*" below in conjunction with the following tables and notes. The recovery and reserve estimates on our properties described herein are estimates only. The actual reserves on our properties may be greater or less than those calculated. See "*Risk Factors*".

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 [1]					
	LIGHT AND MEDIUM CRUDE OIL		CONVENTIONAL NATURAL GAS [2]		NATURAL GAS LIQUIDS	
RESERVES CATEGORY	Gross (Mbbls)	Net (Mbbls)	Gross (MMcf)	Net (MMcf)	Gross (Mbbls)	Net (Mbbls)
PROVED:						
Developed Producing	108,931.5	95,626.0	183,647.4	163,481.1	9,184.2	7,165.7
Developed Non-Producing	4,206.7	3,947.7	6,299.9	5,614.9	182.5	152.7
Undeveloped	72,202.5	65,899.3	110,920.3	102,034.7	6,615.8	5,828.2
TOTAL PROVED	185,340.8	165,472.9	300,867.6	271,130.6	15,982.5	13,146.7
PROBABLE	75,807.6	65,089.8	125,916.5	112,407.2	7,092.8	5,797.9
TOTAL PROVED PLUS PROBABLE	261,148.4	230,562.7	426,784.1	383,537.8	23,075.3	18,944.6

Notes:

(1) Does not include our share of Trident's oil and natural gas reserves. Our 10% equity interest in Trident results in us indirectly having an additional 8.7 Mbbls gross (9.4 Mbbls net) of light and medium crude oil, 52,353.0 MMcf gross (47,848.0 MMcf net) of coal bed methane, 2,160.5 MMcf gross (2,016.1 MMcf net) of conventional natural gas and 5.1 Mbbls gross (3.0 Mbbls net) of natural gas liquids reserves on a proved plus probable basis. This has not been reflected in the table above.

(2) Includes solution gas.

	NET PRESENT VALUES OF FUTURE NET REVENUE BEFORE INCOME TAXES DISCOUNTED AT (%/year) [1]					
RESERVES CATEGORY	0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)	Unit Value Before Income Tax Discounted at 10% per Year $/Boe [2]
PROVED:						
Developed Producing	4,292,773	3,127,387	2,456,535	2,030,434	1,738,466	18.89
Developed Non-Producing	162,841	113,284	84,811	66,939	54,785	16.84
Undeveloped	2,833,591	1,882,934	1,319,525	964,060	726,110	14.87
TOTAL PROVED	7,289,206	5,123,605	3,860,870	3,061,433	2,519,360	17.25
PROBABLE	4,487,740	2,314,460	1,445,357	1,018,490	774,352	16.13
TOTAL PROVED PLUS PROBABLE	11,776,946	7,438,065	5,306,228	4,079,923	3,293,712	16.93

Notes:

(1) Does not include our share of Trident's future net revenue. Our 10% equity interest in Trident results in us indirectly having an additional $89.3 million (undiscounted) in the proved plus probable future net revenue before income taxes. On a discounted basis, we have an interest of $48.0 million, $27.4 million, $17.1 million and $11.6 million, discounted at 5%, 10%, 15% and 20% respectively. This has not been reflected in the table above.

(2) Unit values are based on net reserve values.

RESERVES CATEGORY	NET PRESENT VALUES OF FUTURE NET REVENUE AFTER INCOME TAXES DISCOUNTED AT (%/year) [1] 0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)
PROVED:					
Developed Producing	4,007,508	2,972,288	2,366,387	1,975,191	1,703,144
Developed Non-Producing	118,098	84,843	65,536	53,324	44,886
Undeveloped	2,045,802	1,344,575	925,769	662,458	487,472
TOTAL PROVED	6,171,407	4,401,706	3,357,692	2,690,972	2,235,502
PROBABLE	3,274,479	1,685,672	1,050,992	740,810	564,443
TOTAL PROVED PLUS PROBABLE	9,445,886	6,087,378	4,408,684	3,431,782	2,799,945

Note:

(1) Does not include our share of Trident's future net revenue. Our 10% equity interest in Trident results in us indirectly having an additional $89.3 million (undiscounted) in the proved plus probable future net revenue after income taxes. On a discounted basis, we indirectly have an additional $48.0 million, $27.4 million, $17.1 million and $11.6 million, discounted at 5%, 10%, 15% and 20% respectively. This has not been reflected in the table above.

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

RESERVES CATEGORY	REVENUE [2] ($000s)	ROYALTIES [3] ($000s)	OPERATING COSTS ($000s)	DEVELOPMENT COSTS ($000s)	ABANDONMENT AND RECLAMATION COSTS [4] ($000s)	FUTURE NET REVENUE BEFORE INCOME TAXES ($000s)	INCOME TAXES ($000s)	FUTURE NET REVENUE AFTER INCOME TAXES ($000s)
Total Proved	17,107,965	1,921,585	5,736,379	1,665,863	494,932	7,289,206	1,117,799	6,171,407
Total Proved plus Probable	25,606,943	3,119,959	8,236,069	1,900,367	573,602	11,776,946	2,331,060	9,445,886

Notes:

(1) Does not include our share of Trident's future net revenue. Our 10% equity interest in Trident results in us indirectly having an additional $262.2 million in revenue, less $19.4 million of royalties, $106.5 million of operating costs, $33.9 million of development costs, and $13.1 million of abandonment and reclamation costs to result in $89.3 million of proved plus probable net revenue before and after taxes. This has not been included in the table above.

(2) Includes all product revenues and other revenues as forecast.

(3) Royalties include Crown, freehold and overriding royalties, mineral tax and Saskatchewan Corporate Tax Surcharge.

(4) For more information, see "*Significant Factors and Uncertainties Affecting Reserves Data – Abandonment and Reclamation Costs*".

FUTURE NET REVENUE
BY PRODUCT TYPE
AS OF DECEMBER 31, 2016
FORECAST PRICES AND COSTS [(1)]

RESERVES CATEGORY	PRODUCT TYPE	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) ($000s)	UNIT VALUE [(2)]	
			($/Bbl)	($/Mcf)
Proved	Light and Medium Crude Oil [(3)]	3,823,396	23.11	
	Conventional Natural Gas [(4)]	37,474		1.32
	Total	3,860,870		
Proved plus Probable	Light and Medium Crude Oil [(3)]	5,255,914	22.81	
	Conventional Natural Gas [(4)]	50,313		1.30
	Total	5,306,228		

Notes:

(1) Does not include our share of Trident's future net revenue.
(2) Unit values are calculated using the 10% discount rate divided by the major product type net reserves for each group.
(3) Includes solution gas and other associated by-products.
(4) Includes by-products.

Definitions and Notes to Reserves Data Tables

In the tables set forth above in "*Reserves Data (Forecast Prices and Costs)*" and elsewhere in this Annual Information Form the following definitions and other notes are applicable:

1. "**gross**" means:

    (a) in relation to our interest in production and reserves, our interest (operating and non-operating) share before deduction of royalties and without including any of our royalty interests;

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

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

2. "**net"** means:

    (a) in relation to our interest in production and reserves, our interest (operating and non-operating) share after deduction of royalty obligations, plus our royalty interest in production or reserves;

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

    (c) in relation to our interest in a property, the total area in which we have an interest multiplied by our working interest.

3. Definitions used for reserve categories are as follows:

    Reserve Categories

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

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

(b) the use of established technology; and

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

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

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

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

"**economic assumptions**" are the forecast prices and costs used in the estimate.

Development and Production Status

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

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

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

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

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

Levels of Certainty for Reported Reserves

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

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

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

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

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

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

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

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

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

   (d) provide improved recovery systems.

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

7. "**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 gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

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

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

   (c) dry hole contributions and bottom hole contributions;

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

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

8. "**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.

9. "**forecast prices and costs**"

These are prices and costs that are:

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

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

10. Numbers may not add due to rounding.

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

12. We did not have any heavy crude oil reserves during the year ended December 31, 2016. In addition, we do not have any synthetic oil or other products from non-conventional oil and gas activities other than an immaterial amount from our equity interest in Trident.

Pricing Assumptions

The forecast cost and price assumptions in this statement for our reserves assume primarily increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs.

Crude oil and natural gas benchmark reference pricing, inflation and exchange rates utilized in the McDaniel Report were as follows:

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
FORECAST PRICES AND COSTS (1)

	OIL				NATURAL GAS	NATURAL GAS LIQUIDS	NATURAL GAS LIQUIDS		
Year	WTI Cushing Oklahoma ($US/Bbl)	Edmonton Par Price 40° API ($Cdn/ Bbl)	Hardisty Bow River 25° API ($Cdn/ Bbl)	Hardisty Heavy 12° API ($Cdn/ Bbl)	AECO Gas Price ($Cdn/ MMbtu)	Edmonton Propane ($Cdn/Bbl)	Edmonton Butane ($Cdn/Bbl)	INFLATION RATES %/Year (2)	EXCHANGE RATE ($US/$Cdn) (3)
Forecast									
2017	55.00	69.80	54.40	46.50	3.40	23.30	43.50	-	0.750
2018	58.70	72.70	58.90	50.50	3.15	23.70	47.90	2.00	0.775
2019	62.40	75.50	62.70	54.00	3.30	26.20	49.80	2.00	0.800
2020	69.00	81.10	67.30	58.00	3.60	28.30	56.40	2.00	0.825
2021	75.80	86.60	71.90	61.90	3.90	30.30	63.40	2.00	0.850
2022	77.30	88.30	73.30	63.10	3.95	30.90	64.70	2.00	0.850
2023	78.80	90.00	74.70	64.40	4.10	31.50	65.90	2.00	0.850
2024	80.40	91.80	76.20	65.60	4.25	32.20	67.30	2.00	0.850
2025	82.00	93.70	77.80	67.00	4.30	32.90	68.60	2.00	0.850
2026	83.70	95.60	79.30	68.40	4.40	33.60	70.00	2.00	0.850
2027	85.30	97.40	80.80	69.60	4.50	34.20	71.40	2.00	0.850
2028	87.00	99.40	82.50	71.10	4.60	34.90	72.80	2.00	0.850
2029	88.80	101.40	84.20	72.50	4.65	35.60	74.30	2.00	0.850
2030	90.60	103.50	85.90	74.00	4.75	36.30	75.80	2.00	0.850
2031	92.40	105.50	87.60	75.40	4.85	37.10	77.30	2.00	0.850
Thereafter	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	2.00	0.850

Notes:

(1) As at January 1, 2017.
(2) Inflation rate for costs.
(3) Exchange rate used to generate the benchmark reference prices in this table.

Weighted average historical prices realized by us for the year ended December 31, 2016, excluding price risk management activities, were $2.26/Mcf for conventional natural gas, $47.58/Bbl for light and medium crude oil, and $17.31/Bbl for natural gas liquids.

The forecast prices used in the Trident Report were specified by Trident. Oil and condensate prices were based on a December 31, 2016, forecast of Edmonton light prices prepared by a Canadian independent consultant and were adjusted by field for quality, transportation fees, and market differentials. Natural gas and coal bed methane prices were based on a December 31, 2016, forecast of AECO-C prices prepared by a Canadian independent consultant and were adjusted by field for energy content, transportation fees, and market differentials. As requested by Trident, economic projections are included in the proved developed producing category to account for the effect of certain coal bed methane price hedge contracts which Trident has in place through December 31, 2018.

Forecast case prices, before adjustments, along with escalation parameters used in the Trident Report are shown in the following table:

Period Ending	**Oil/Condensate Price (C$/Bbl)**	**Natural Gas/CBM Price (C$/MMBtu)**
12-31-2017	69.80	3.40
12-31-2018	72.70	3.15
12-31-2019	75.50	3.30
12-31-2020	81.10	3.60
12-31-2021	86.60	3.90
12-31-2022	88.30	3.95
12-31-2023	90.00	4.10
12-31-2024	91.80	4.25
12-31-2025	93.70	4.30
12-31-2026	95.60	4.40
12-31-2027	97.40	4.50
12-31-2028	99.40	4.60
12-31-2029	101.40	4.65
12-31-2030	103.50	4.75
12-31-2031	105.50	4.85

Thereafter, escalated at 2.0% on January 1 of each year.

Reserves Reconciliation

RECONCILIATION OF
GROSS RESERVES
BY PRODUCT TYPE
FORECAST PRICES AND COSTS [1]

	LIGHT AND MEDIUM CRUDE OIL			HEAVY CRUDE OIL		
	Gross Proved (Mbbls)	**Gross Probable (Mbbls)**	**Gross Proved Plus Probable (Mbbls)**	**Gross Proved (Mbbls)**	**Gross Probable (Mbbls)**	**Gross Proved Plus Probable (Mbbls)**
December 31, 2015	140,725.3	52,952.3	193,677.6	18.9	6.0	24.9
Extensions & Improved Recovery	8,917.4	3,647.3	12,564.7	-	-	-
Technical Revisions	(3,206.8)	(5,540.2)	(8,747.0)	(18.9)	(6.0)	(24.9)
Discoveries	-	-	-	-	-	-
Acquisitions [2]	54,263.8	25,818.5	80,082.3	-	-	-
Dispositions	(2,812.1)	(873.2)	(3,685.3)	-	-	-
Economic Factors	(700.4)	(197.1)	(897.5)	-	-	-
Production	(11,846.4)	-	(11,846.4)	-	-	-
December 31, 2016	185,340.8	75,807.6	261,148.4	-	-	-

	CONVENTIONAL NATURAL GAS[3]			NATURAL GAS LIQUIDS		
	Gross Proved (MMcf)	**Gross Probable (MMcf)**	**Gross Proved Plus Probable (MMcf)**	**Gross Proved (Mbbls)**	**Gross Probable (Mbbls)**	**Gross Proved Plus Probable (Mbbls)**
December 31, 2015	271,429.8	117,371.2	388,801.0	13,632.1	6,259.9	19,892.0
Extensions & Improved Recovery	17,886.1	8,630.8	26,516.9	1,014.2	485.1	1,499.3
Technical Revisions	30,062.5	(1,629.8)	28,432.7	2,331.7	254.2	2,585.9
Discoveries	-	-	-	-	-	-
Acquisitions [2]	7,431.0	2,777.1	10,208.1	312.8	146.9	459.7
Dispositions	(536.2)	(163.2)	(699.4)	(19.7)	(6.0)	(25.7)
Economic Factors	(2,841.2)	(1,069.6)	(3,910.8)	(117.9)	(47.3)	(165.2)
Production	(22,564.4)	-	(22,564.4)	(1,170.7)	-	(1,170.7)
December 31, 2016	300,867.6	125,916.5	426,784.1	15,982.5	7,092.8	23,075.3

Notes:

(1) Does not include our share of Trident's oil and natural gas reserves.
(2) The acquisitions amount is the estimate of reserves at December 31, 2016 plus any production since the acquisition dates.
(3) Includes solution gas volumes.

Additional Information Relating to Reserves Data

Undeveloped Reserves

Undeveloped reserves are attributed by McDaniel in accordance with standards and procedures contained in the COGE Handbook. Proved undeveloped reserves are those reserves that can be estimated with a high degree of certainty and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Probable undeveloped reserves are those reserves that are less certain to be recovered than proved reserves and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production.

All of our proved undeveloped reserves are in our core areas where we are actively spending capital to develop those properties. As such, we expect that the large majority of our booked undeveloped projects will be completed within a three year time frame and that substantially all of our currently booked undeveloped projects will be completed within a five year time frame. For more information, see "*Future Development Costs*". There are a number of factors that could result in delayed or cancelled development, including the following: (i) changing economic conditions (due to pricing, operating and capital expenditure fluctuations); (ii) changing technical conditions (including production anomalies, such as water breakthrough or accelerated depletion); (iii) multi-zone developments (for instance, a prospective formation completion may be delayed until the initial completion is no longer economic); (iv) a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and (v) surface access issues (including those relating to land owners, weather conditions and regulatory approvals). For more information, see "*Risk Factors*".

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 (1) (Mbbls)		Heavy Crude Oil (1) (Mbbls)		Conventional Natural Gas (1) (MMcf)		Natural Gas Liquids (1) (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	14,953.1	42,617.4	33.0	33.0	23,345.3	82,514.4	1,185.5	4,243.9
2015	26,608.5	63,618.0	-	-	27,737.5	99,769.1	1,885.6	5,603.0
2016	17,656.7	72,202.5	-	-	15,156.7	110,920.3	1,001.0	6,615.8

Note:

(1) Does not include our share of Trident's oil and natural gas reserves.

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. McDaniel has assigned 97.3 MMboe of proved undeveloped reserves in the McDaniel Report with $1,665.9 million of associated undiscounted capital.

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 (1) (Mbbls)		Heavy Crude Oil (1) (Mbbls)		Conventional Natural Gas (1) (MMcf)		Natural Gas Liquids (1) (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	8,448.1	19,721.4	57.0	57.0	9,908.8	43,300.0	727.0	2,265.8
2015	10,528.1	26,835.3	-	-	15,143.6	54,474.1	1,169.3	3,269.9
2016	15,061.4	38,591.5	-	-	8,238.6	61,532.3	528.7	3,912.7

Note:

(1) Does not include our share of Trident's oil and natural gas reserves.

Probable undeveloped reserves have been assigned in areas where the reserves can be estimated with less certainty. It is equally likely that 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. McDaniel has assigned 52.8 MMboe of probable undeveloped reserves in the McDaniel Report with $234.5 million of associated undiscounted capital.

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 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, abandonment and reclamation costs and well performance that are beyond our control. See "*Risk Factors*".

Abandonment and Reclamation Costs

In connection with our operations, we will incur abandonment and reclamation costs for surface leases, wells, facilities and pipelines. We budget for and recognize as a liability the estimated present value of the future decommissioning liabilities associated with our property, plant and equipment. Our overall abandonment and reclamation costs include all costs associated with the process of restoring a property that has been disturbed by oil and gas activities to the standard imposed by the applicable government or regulatory authorities. These costs were estimated using our experience conducting abandonment and reclamation programs. We review suspended or standing wells for reactivation, recompletion or sale and conduct systematic abandonment programs for those wells that do not meet our criteria. A portion of our liability issues are retired every year and facilities are decommissioned when all the wells producing to them have been abandoned. All of our liability reduction programs take into account seasonal access, high priority and stakeholder issues, and opportunities for multi-location programs to reduce costs. There are no unusually significant abandonment and reclamation costs associated with our properties with attributed reserves.

As at December 31, 2016 we had 4,260 net wells for which we expect to incur abandonment and reclamation costs. The McDaniel Report deducted $573.6 million (undiscounted) and $39.5 million (10% discount) for abandonment and reclamation costs of wells with proved and probable reserves, in estimating the future net revenues disclosed in this Annual Information Form.

The future net revenues disclosed in this Annual Information Form based on the McDaniel Report do not contain an allowance for abandonment and reclamation costs for facilities, pipelines or wells without reserves. Management has also estimated there is an additional $337.8 million (undiscounted) and $24.8 million (10% discount) not included in the future net revenues disclosed in this Annual Information Form for abandonment and reclamation costs for facilities and pipelines and an additional $118.4 million (undiscounted) and $38.9 (10% discounted) for abandonment and reclamation costs for wells without reserves.

Future Development Costs

The following table sets forth development costs deducted in the estimation of our future net revenue attributable to the reserve categories noted below. The table below includes a proactive increase to our future development costs of approximately 10% or $165 million requested by us to account for what we anticipate will be future service cost inflation.

	FORECAST PRICES AND COSTS	
Year	**Proved Reserves (1) ($000s)**	**Proved Plus Probable Reserves (1) ($000s)**
2017	320,045	321,121
2018	423,046	426,255
2019	419,168	460,417
2020	286,508	372,764
2021	194,905	252,299
Remaining	22,191	67,512
Total (Undiscounted)	**1,665,863**	**1,900,367**

Note:

(1) Does not include our share of Trident's future development costs.

We expect to fund the development costs of our reserves through a combination of internally generated cash flow, debt 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 McDaniel Report. Failure to develop those reserves could have a negative impact on our future cash flow.

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.

Other Oil and Natural Gas Information

Principal Properties

The following is a description of our principal oil and natural gas properties on production or under development as at December 31, 2016. Information in respect of current production is average production, net to our working interest, except where otherwise indicated.

West Central Alberta

Our Cardium producing areas in West Central Alberta are primarily located in the Pembina, Garrington, Ferrier and Willesden Green areas. The key characteristics of the Cardium in these areas are light 40° API oil with geology and oil resource mapping that is well defined with legacy vertical wells. There is no significant mobile formation water in the Cardium which results in predictable declines and production profiles. Several of these legacy pools are under active waterflood which has the impact of lowering pool declines and increasing the percentage of the oil in place which is recoverable. Performance of these waterfloods has been improving with optimization efforts.

Our Elnora producing property is located southeast of Red Deer, Alberta. This recent conventional light oil Nisku discovery is one of the largest discoveries of its kind in the last 20 years. The key characteristics of this property are light sweet 35° API oil, excellent reservoir quality, with a natural aquifer waterdrive, supplemented with water injection, which provides prolific and predictable production.

Southwest Saskatchewan

Our Southwest Saskatchewan assets are concentrated west of Swift Current, Saskatchewan and are characterized by predictable low base decline, medium crude oil (21° API) production. Multiple active waterfloods are sustaining the area as well as three established ASP floods with 92% of production coming from enhanced recovery. Additional waterflood and ASP potential exists, and will be part of our ongoing development programs. The primary formations being targeted in the area are Atlas, Success, Roseray, and Shaunavon. The properties have not seen significant development over the last several years, and we will utilize horizontal wells, multistage fracing technology, and conventional optimization efforts to further develop these assets.

Northwest Alberta and British Columbia

Our Boundary Lake property is located primarily in northeast British Columbia on the Alberta/British Columbia border, just east of Fort St. John, and is characterized by shallow declines and a predictable production base within an active waterflood. The key characteristics of this legacy oil pool are high working interest, operated, light 35° API oil and a low base production decline rate.

Our Valhalla North property is located in the Peace River Arch area of Alberta and is characterized by shallow declines and a predictable production base. The primary reservoir that we are currently focused on is the Montney Sexsmith oil pool and associated waterflood. The key characteristics of the pool are light 36° API oil, homogeneous reservoir quality and no original moveable water formation.

Our Deep Basin properties, which include Karr, Simonette, Kakwa, Elmworth and Wapiti, are located southwest of Grande Prairie, Alberta. The primary reservoirs being developed are the Dunvegan and Cardium, which are light sweet (39° - 42° API) oil. Both reservoirs are characterized by thick oil columns with significant oil in place per unit area. This area is being developed with horizontal multi-fracture wells, including extended reach horizontals that exhibit a lower decline profile than in many areas due to the significant oil in place.

West Central Saskatchewan

Our Lucky Hills, Whiteside, Kerrobert, and Eagle Lake areas are located in West Central Saskatchewan. The primary reservoir that we are currently focused on developing is the Viking resource oil play. The key characteristics of this play is light 38° – 40° API oil, predictable geology and production profiles as well as consistent and repeatable economics. Lucky Hills and Whiteside are characterized by horizontal primary oil development wells with quick payouts and a high operating netback production profile. The Eagle Lake property is characterized by low decline waterflood supported production from legacy vertical and horizontal infill wells. Additional development is ongoing through the drilling of infill horizontal wells and reactivation of the waterfloods to increase reserve recoveries. Kerrobert is very much analogous to Eagle Lake with reservoir properties conducive to successful waterflooding. The Kerrobert waterflood is in its infancy of development, relative to Eagle Lake, and as a result has significant upside related to reserve recovery and decline stabilization.

Oil And Natural Gas Wells and Unproved Properties

The following table summarizes, as at December 31, 2016, our interests in producing wells and in non-producing wells.

	Producing Wells (1)(2)				**Non-Producing Wells (1)(2)**			
	Oil		**Natural Gas**		**Oil**		**Natural Gas**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Alberta	949	757.0	111	55.1	400	315.7	211	119.5
British Columbia	189	172.4	23	10.3	132	122.0	18	9.5
Saskatchewan	2,815	2,154.3	5	3.9	1,641	1,257.2	85	64.3
Total	3,953	3,083.7	139	69.3	2,173	1,695.0	314	193.4

Notes:

(1) Does not include injection wells or service wells.
(2) Does not include our interests in Trident's producing wells and non-producing wells.

Developed and Undeveloped Lands

The following table sets out our developed and undeveloped land holdings as at December 31, 2016.

	UNDEVELOPED ACRES		**DEVELOPED ACRES**		**TOTAL ACRES (1)(2)(3)(4)**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Alberta	215,688	160,067	325,511	231,511	541,200	391,578
Saskatchewan	153,909	125,424	244,878	176,651	398,787	302,075
British Columbia	25,186	18,182	61,727	50,978	86,913	69,160
Total	394,783	303,673	632,116	459,140	1,026,900	762,813

Notes:

(1) Includes our interest in approximately 141,949 gross acres of unproved property land holdings.
(2) Rights to explore, develop and exploit 39,881 net acres of our land holdings could expire by December 31, 2017 if not continued. We have no material work commitments on such properties and where we determine prudent to do so, we can extend expiring leases by either making the necessary applications to extend or performing the necessary work.
(3) When determining gross and net acreage for two or more leases covering the same lands but different rights, the acreage is reported for each lease. Where there are multiple discontinuous rights in a single lease, the acreage is reported only once.
(4) Does not include our interest in Trident's developed and undeveloped land holdings.

Significant Factors or Uncertainties Relevant to Properties with no Attributed Reserves

Our business model focuses on predictable and lower decline production with little to no capital allocated to the acquisition, exploration or development of our properties with no attributed reserves. We do not anticipate any significant economic factors or significant uncertainties will affect any particular components of our properties with no attributed reserves. However, our decision to develop our properties with no attributed reserves can be affected significantly by fluctuations in product pricing, capital expenditures, operating costs and royalty regimes, all of which are beyond our control. There are no unusually significant abandonment and reclamation costs with our properties with no attributed reserves. See "*Significant Factors and Uncertainties Affecting Reserves Data – Abandonment and Reclamation Costs*" and "*Risk Factors*".

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 5 to our consolidated financial statements for the year ended December 31, 2016. See "*Risk Factors – Hedging*".

Tax Horizon

Based on estimated 2017 cash flow and capital expenditures, we do not expect to be cash taxable in 2017. We currently estimate that we will not become taxable until at least 2020, using forward benchmark prices in effect on the date of this AIF.

Costs Incurred

The following table summarizes the costs incurred related to our activities for the year ended December 31, 2016.

Expenditure	**Year Ended December 31, 2016 ($000s)**
Property acquisition costs – unproved properties [1]	283
Property acquisition costs – proved properties [2]	486,186
Exploration costs [3]	821
Development costs [4]	168,391
Other	4,863
Total	660,544

Notes:

(1) Cost of land acquired and non-producing lease rentals on those lands.
(2) Net of dispositions.
(3) Geological and geophysical capital expenditures and drilling costs for exploration wells.
(4) Development costs include development drilling costs and equipping, tie-in and facility costs for all wells.

Exploration and Development Activities

The following table sets forth the gross development wells in which we participated during the year ended December 31, 2016. We did not participate in any exploratory wells during the year.

	Development	
	Gross	**Net**
Natural Gas	-	-
Light and Medium Crude Oil	104	94.1
Dry	-	-
Total	104	94.1

In 2017, we expect to drill approximately 45 oil wells in Alberta, 137 oil wells in Saskatchewan and 5 oil wells in British Columbia.

Production Estimates

The following table sets out the volumes of our working interest production estimated for the year ended December 31, 2017, which is reflected in the estimate of future net revenue disclosed in the forecast price tables contained above under the subheading "*Disclosure of Reserves Data*".

	Light and Medium Crude Oil (Bbls/d)	**Conventional Natural Gas (Mcf/d)**	**Natural Gas Liquids (Bbls/d)**	**BOE (Boe/d)**
Total Proved				
Northwest Alberta and British Columbia	9,161.5	24,283.2	672.9	13,881.6
West Central Alberta	13,845.6	28,881.1	1,650.2	20,309.4
West Central Saskatchewan	10,297.0	12,599.6	282.1	12,679.1
Southwest Saskatchewan	12,082.4	1,160.9	1.0	12,276.9
Minors	14.9	304.0	0.4	66.0
Total	45,401.4	67,228.8	2,606.6	59,212.9
Total Proved plus Probable				
Northwest Alberta and British Columbia	9,605.6	25,396.9	711.2	14,549.6
West Central Alberta	15,110.1	30,418.9	1,741.7	21,921.7
West Central Saskatchewan	11,595.7	14,129.1	315.9	14,266.5
Southwest Saskatchewan	12,433.8	1,204.8	1.0	12,635.6
Minors	15.3	309.3	0.4	67.2
Total	48,760.5	71,459.0	2,770.3	63,440.6

Production History

The following table indicates our average daily production (including production from our major areas) for the year ended December 31, 2016.

	Light and Medium Crude Oil (Bbls/d)	**Natural Gas Liquids (Bbls/d)**	**Conventional Natural Gas (Mcf/d)**	**BOE [(1)] (Boe/d)**
Northwest Alberta and British Columbia	6,728	820	23,673	11,494
West Central Alberta	11,975	2,079	29,300	18,937
West Central Saskatchewan	7,542	268	7,923	9,131
Southwest Saskatchewan	6,142	1	493	6,225
Minors	11	-	262	55
Total	32,398	3,168	61,651	45,841

Note:

(1) We did not produce any heavy oil during the year ended December 31, 2016.

The following tables summarize certain information in respect of our production, product prices received, royalties paid, production costs and resulting operating netback for the periods indicated below:

	Quarter Ended				Year Ended
	Mar. 31, 2016	Jun. 30, 2016	Sep. 30, 2016	Dec. 31, 2016	Dec. 31, 2016
Average Daily Production (1)(2)					
Light and Medium Crude Oil (bbls/d)	29,561	26,771	36,094	37,072	32,398
Natural Gas Liquids (bbls/d)	3,205	3,231	2,991	3,247	3,168
Conventional Natural Gas (MMcf/d)	61,547	62,315	60,994	61,756	61,651
Combined (boe/d)	43,024	40,388	49,251	50,612	45,841
Average Net Production Prices Received					
Light and Medium Crude Oil ($/bbl)	36.54	50.18	48.14	53.88	47.58
Natural Gas Liquids ($/bbl)	10.69	17.33	17.47	23.60	17.31
Conventional Natural Gas ($/Mcf)	1.91	1.45	2.47	3.23	2.26
Combined ($/boe)	28.63	36.88	39.39	44.92	37.87
Royalties Paid					
Light and Medium Crude Oil ($/bbl)	4.86	6.70	8.18	8.84	7.31
Natural Gas Liquids ($/bbl)	3.88	4.50	4.06	6.47	4.75
Conventional Natural Gas ($/Mcf)	0.08	(0.12)	(0.20)	-	(0.06)
Combined ($/boe)	3.75	4.61	5.99	6.89	5.42
Production Costs (3)(4)(5)					
Light and Medium Crude Oil ($/bbl)	12.81	14.00	12.16	13.79	13.16
Natural Gas Liquids ($/bbl)	-	-	-	-	-
Conventional Natural Gas ($/Mcf)	0.15	0.15	0.18	0.16	0.16
Combined ($/boe)	9.97	10.63	9.88	11.18	10.43
Operating Netback Received					
Light and Medium Crude Oil ($/bbl)	18.87	29.47	27.80	31.25	27.10
Natural Gas Liquids ($/bbl)	6.81	12.83	13.41	17.13	12.56
Conventional Natural Gas ($/Mcf)	1.68	1.42	2.48	3.07	2.16
Combined ($/boe)	14.91	21.64	23.52	26.85	22.02

Notes:

(1) Before the deduction of royalties.
(2) We did not produce any heavy oil during the year ended December 31, 2016.
(3) Production costs are composed of direct costs incurred to operate both oil and gas wells. A number of assumptions are required to allocate these costs between product types.
(4) Operating recoveries associated with operated properties are charged to production costs and accounted for as a reduction to general and administrative costs.
(5) Production costs attributable to natural gas liquids have been included in the light and medium crude oil and conventional natural gas production cost amounts.

DESCRIPTION OF OUR CAPITAL STRUCTURE

Credit Facility

Our $1.1 billion Credit Facility is comprised of a $678 million revolving production facility, a $50 million revolving operating facility and $372 million term loan facilities.

At the end of the revolving period, being April 30, 2017, the extendible revolving credit facility converts into a 366-day term loan if not renewed. The revolving facilities may be extended for a further 364-day revolving period upon our request, subject to approval by the banks. The first $188 million term loan facility matures on October 3, 2018 and the second $184 million term loan facility matures on May 1, 2019.

The Credit Facility bears interest at the banks' prime lending or bankers' acceptance rates plus applicable margins. The applicable margin charged by the bank is dependent upon our debt to earnings before interest, taxes, depreciation and amortization (EBITDA) ratio for the most recent quarter annualized. The first $188 million term loan facility has an effective interest rate of 5.3%. The second $184 million term loan facility has an effective interest rate of 4.7%.

We are required to comply with various covenants under the Credit Facility including two financial covenants, where the ratio of our debt to EBITDA shall not exceed 4.0:1.0 and the ratio of our EBITDA/interest expense shall not be less than 3.5:1.0. The debt used in the covenant calculation includes bank indebtedness, the notes, letters of credit, and dividends declared.

The Credit Facility is secured by a $3 billion demand debenture in respect of all of our assets and a general assignment of book debts in respect of all of our accounts. The borrowing base is generally subject to review and redetermination by the lenders on an annual basis or in the event of a change in our borrowing base properties. See "*Risk Factors – Credit Facility Arrangements*".

Pursuant to the terms of the Credit Facility, we are permitted to pay dividends provided that, if at both the date of declaration and payment of any such dividend, there is no borrowing base shortfall under the Credit Facility which has not been eliminated, no default has occurred which has not been cured or waived and no default or event of default could reasonably be expected to be caused by or result from such declaration or payment.

Senior Secured Notes

We issued $200 million in senior secured notes by way of private placement on January 5, 2017. The Senior Secured Notes are repayable on January 5, 2022 and have an annual coupon rate of 3.46%. The significant covenants under the Senior Secured Notes are the same as those under the Credit Facility, see "*Description of our Capital Structure – Credit Facility*".

Share Capital

The following is a description of the rights, privileges, restrictions and conditions attaching to our share capital.

Common Shares

We are authorized to issue an unlimited number of Common Shares without nominal or par value. Subject to the provisions of the *Business Corporations Act* (Alberta), holders of our Common Shares are entitled to one vote per share at meetings of our Shareholders. Subject to the rights of the holders of preferred shares and any other shares having priority over the Common Shares, holders of Common Shares are entitled to dividends if, as and when declared by our Board of Directors and upon liquidation, dissolution or winding-up to receive, our remaining property.

Preferred Shares

We are authorized to issue an unlimited number of preferred shares without nominal or par value. Our Board of Directors may issue preferred shares at any time and from time to time in one or more series and shall fix the number of preferred shares in such series and determine the designation, rights, privileges, restrictions and conditions attaching the preferred shares. The preferred shares shall be entitled to priority over our Common Shares and over any other of our shares ranking junior to the preferred shares with respect to priority in the payment of dividends if, as and when declared by our Board of Directors and the receipt of our remaining property upon liquidation, dissolution or winding-up. There are currently no preferred shares issued or outstanding.

MARKET FOR OUR SECURITIES

Trading Price and Volume

Our Common Shares trade on the Toronto Stock Exchange under the trading symbol "WCP". The following sets out the high and low trading prices and aggregate volume of trading on the Toronto Stock Exchange for the periods noted below for the Common Shares:

Period	High	Low	Volume
2016			
January	9.20	5.80	85,195,159
February	7.66	5.60	69,101,032
March	8.86	7.36	59,482,582
April	10.10	7.03	61,631,890
May	10.43	8.60	59,182,994
June	10.95	9.49	46,173,481
July	10.28	9.12	32,500,252
August	10.82	9.47	32,657,431
September	11.43	9.84	43,652,033
October	11.74	10.46	27,597,409
November	12.01	10.38	35,174,750
December	12.90	11.67	19,056,566
2017			
January	12.76	10.19	28,777,635
February	11.48	9.99	29,434,843
March (1-6)	11.00	10.47	7,937,724

Prior Sales

During the year ended December 31, 2016 we issued a total of 1,532,000 share awards pursuant to our share award plan. On the payment date of such awards we have the sole discretion as to whether the awards shall be paid in cash, Common Shares from treasury or Common Shares purchased on the Toronto Stock Exchange. See note 13 of our annual consolidated financial statements for additional information.

DIRECTORS AND OFFICERS

The names, municipalities of residence, any offices held with us, the period served as a director and principal occupations of our directors and officers are set out below.

Name and Municipality of Residence	Position with Whitecap	Director or Officer Since	Principal Occupation
Grant B. Fagerheim (2)(4) Calgary, Alberta	Chairman, President, Chief Executive Officer and Director	June 2008	Our President and Chief Executive Officer.
Gregory S. Fletcher (1)(2) Calgary, Alberta	Director	September 2010	President of Sierra Energy Inc., a private oil and gas production company.

Name and Municipality of Residence	Position with Whitecap	Director or Officer Since	Principal Occupation
Daryl H. Gilbert (3)(4) Calgary, Alberta	Director	July 2015	Managing Director and Investment Committee Member of JOG Capital Inc. since May 2008, a private equity energy investment firm. Prior thereto, from January 2005 to May 2008, independent businessman. Prior thereto, from 1994 to 2005, President and Chief Executive Officer of Gilbert Laustsen Jung Associates Ltd., now GLJ Petroleum Consultants Ltd., an independent engineering consulting firm.
Glenn A. McNamara (2)(3) Calgary, Alberta	Director	September 2010	President and Chief Executive Officer of Heritage Royalty, a private fee title acreage owner company. Prior thereto he was the Chief Executive Officer and a director of PMI Resources Ltd. (formerly, Petromanas Energy Inc.), a public oil and gas company from September 2010 to May 2016. From August 2005 to August 2010, Mr. McNamara was the President of BG Canada (part of the BG Group PLC, a public gas company with its head office in the United Kingdom, trading on the London Stock Exchange). Prior thereto he was the President of ExxonMobil Canada Energy (a wholly-owned subsidiary of ExxonMobil).
Stephen C. Nikiforuk (1) Calgary, Alberta	Director	August 2009	President of MyOwnCFO Professional Corporation since October 2011; President of MyOwnCFO Inc. from July 2009 to June 2012 (both private companies); Corporate Business Manager of 1173373 Alberta Ltd. (a private company) from July 2009 to July 2011; Vice President, Finance and Chief Financial Officer of Cadence Energy Inc. (formerly, Kereco Energy Ltd.), a public oil and gas company, from January 2005 to March 2008.
Kenneth S. Stickland (1)(3) Calgary, Alberta	Director	June 2013	Independent businessman. Prior thereto, he was Chief Business Development Officer of TransAlta Corporation, a publicly traded electricity generating and marketing company from December 2012 to February 2014; September 2001 to December 2012, Chief Legal and Business Development Officer of TransAlta Corporation; May 2009 to September 2011 Chief Legal Officer of TransAlta Corporation.
Grant A. Zawalsky (4) Calgary Alberta	Director	June 2008	Managing Partner of Burnet, Duckworth & Palmer LLP, (Barristers and Solicitors) where he has been a partner since 1994.
Joel M. Armstrong Calgary, Alberta	Vice President, Production and Operations	May 2010	Our Vice President, Production and Operations.
Daniel J. Christensen Calgary, Alberta	Vice President, Exploration	September 2009	Our Vice President, Exploration.

Name and Municipality of Residence	Position with Whitecap	Director or Officer Since	Principal Occupation
Darin R.Dunlop Calgary, Alberta	Vice President, Engineering	November 2009	Our Vice President, Engineering.
Thanh C. Kang Calgary, Alberta	Chief Financial Officer	September 2009	Our Chief Financial Officer.
P. Gary Lebsack Calgary, Alberta	Vice President, Land	September 2009	Our Vice President, Land.
David M. Mombourquette Calgary, Alberta	Vice President, Business Development	September 2009	Our Vice President, Business Development.
Jeffery B. Zdunich Calgary, Alberta	Vice President, Finance and Controller	January 2015	Our Vice President, Finance and Controller since January 2015; Our Controller since March 2011.

Notes:

(1) Member of our Audit Committee.
(2) Member of our Reserves Committee.
(3) Member of our Corporate Governance & Compensation Committee.
(4) Member of our Health, Safety & Environment Committee.

The term of office of each of our directors expires at the next annual meeting of our Shareholders.

As at March 6, 2017 our directors and executive officers, as a group, beneficially owned, or directed or controlled, directly or indirectly, 7.0 million Common Shares or approximately 1.9% of our issued and outstanding Common Shares.

Corporate Cease Trade Orders, Bankruptcies or Penalties or Sanctions

Other than as set out below and 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.

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 other than described below

Mr. Fagerheim was formerly a director of The Resort at Copper Point Ltd. (a private real estate development company) which was placed in receivership in February 2009. Mr. Nikiforuk was a director of CYGAM Energy Inc. (a junior public oil and gas company) which filed a voluntary assignment in bankruptcy under the *Bankruptcy and Insolvency Act* (Canada) in April 2015. Mr. Gilbert was a director of Globel Direct Inc. ("**Globel**"), a public business process outsource company, from December 1998 to June 2009. Globel sought and received protection under the *Companies' Creditors Arrangement Act* (Canada) ("**CCAA**") in June 2007. After a failed restructuring effort, on December 12, 2007, a receiver was appointed by one of the Globel's lenders. Globel ceased operations and as a result became the subject of cease trade orders from the Alberta Securities Commission and the British Columbia Securities Commission on September 30, 2008. Mr Gilbert was a director of LGX Oil and Gas Inc. ("**LGX**") from August, 2013 until June 2016. On June 7, 2016 a consent receivership order was granted by the Alberta Court of Queen's Bench (the "**Court**") upon an application by LGX's senior lender. LGX's stock was cease traded shortly thereafter. A receiver manager was appointed and a liquidation process is underway. Mr. Gilbert has been a director of Connacher Oil & Gas Limited ("**Connacher**") since October 2014. On May 17, 2016, Connacher applied for and was granted protection from its creditors by the Court pursuant to the CCAA. Connacher was cease traded immediately following the Court order. A restructuring process is currently underway. Mr. Stickland was a director of Millennium Stimulation Services Ltd. ("**Millennium**") a private company from May 3, 2012 to March 23, 2016. On March 24, 2016, the Court issued an order appointing KPMG Inc. as receiver and manager over Millennium's assets, undertakings and other properties. As at January 17, 2017, Millennium is still under receivership. Mr. Zawalsky was a director of Endurance Energy Ltd. ("**Endurance**"), a private corporation engaged in the exploration and production of natural gas in western Canada. Endurance filed for creditor protection under the CCAA on May 30, 2016. Mr. Zawalsky resigned as a director of Endurance on November 3, 2016 upon the sale of substantially all of the assets of Endurance.

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, 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 Shareholder 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*".

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 *Business Corporations Act* (Alberta) 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 *Business Corporations Act* (Alberta). To the extent that conflicts of interests arise, such conflicts will be resolved in accordance with the provisions of the *Business Corporations Act* (Alberta).

AUDIT COMMITTEE INFORMATION

Audit Committee Charter

The full text of our Audit Committee charter is included in Appendix C of this Annual Information Form.

Composition of the Audit Committee

The members of our Audit Committee are Mr. Nikiforuk (Chair), Mr. Stickland and Mr. Fletcher, each of whom is independent and financially literate. We have adopted the definition of "independence" as set out in Section 1.4 of National Instrument 52-110 – *Audit Committees*. The relevant education and experience of each Audit Committee member is outlined below:

Stephen C. Nikiforuk*: MyOwnCFO Professional Corporation*

Mr. Nikiforuk has been the President of MyOwnCFO Professional Corporation since October 2011 and was the President of MyOwnCFO Inc. from July 2009 to June 2012, both private companies. Before then, Mr. Nikiforuk was the Corporate Business Manager of 1173373 Alberta Ltd. (a private company) from July 2009 to July 2011 and the Vice President, Finance and Chief Financial Officer of Cadence Energy Inc. (formerly, Kereco Energy Ltd.) a public oil and gas company, from January 2005 to March 2008.

Mr. Nikiforuk holds a B.B.A. with an accounting major from Saint Francis Xavier University. Mr. Nikiforuk is an active Chartered Professional Accountant, CA and in 2013 completed the Directors Education Program developed by the Institute of Corporate Directors and holds their ICD.D designation. In June 2016, Mr. Nikiforuk also obtained the Family Enterprise Advisor designation.

Mr. Nikiforuk is also a director of CanAir Nitrogen Inc., a private company that supplies the oil and gas industry in Alberta and British Columbia with cryogenic liquid nitrogen, and InPlay Oil Corp., a public light oil production and development company, and serves as Audit Committee Chair for InPlay Oil Corp. Mr. Nikiforuk is also on the board of a charitable foundation.

Kenneth S. Stickland*: Independent Businessman*

Mr. Stickland is an independent businessman. Prior to February 1, 2014, he was employed for 13 years by TransAlta Corporation, one of Canada's largest non-regulated power generation and wholesale marketing companies. At TransAlta he held the position of Chief Business Development Officer and prior to that was the Chief Legal Officer. Prior thereto, Mr. Stickland was a partner with the Calgary based law firm of Burnet, Duckworth & Palmer LLP and has over 30 years of experience in the area of commercial law with a specific focus on energy-related matters. Mr. Stickland has been the director of various associations and not-for-profit organizations. He has also been the director of several publicly listed companies. In these roles, Mr. Stickland has acquired significant experience and exposure to accounting and financial reporting issues. Mr. Stickland is also a director of Trinidad Drilling Ltd., a public oilfield services company.

Gregory S. Fletcher*: Sierra Energy Inc.*

Mr. Fletcher is an independent businessman involved in the oil and natural gas industry in western Canada. He is currently President of Sierra Energy Inc., a private oil and natural gas production company that he founded in 1997. Mr. Fletcher is also a director of Peyto Exploration & Development Corp., a public oil and natural gas company, a director of Calfrac Well Services Ltd., a public oilfield service company and a director of Total Energy Services Inc., a public oilfield service company. In these roles, Mr. Fletcher has acquired significant experience and exposure to accounting and financial reporting issues. During 2009, Mr. Fletcher completed the Director Education Program developed by the Institute of Corporate Directors and the Rotman School of Management in conjunction with the Haskayne School of Business. Mr. Fletcher holds a BSc. in geology from the University of Calgary.

Pre-Approval of Policies and Procedures

Our Audit Committee has adopted a policy to review and pre-approve any non-audit services to be provided to us by our external auditors and will consider the impact on the independence of such auditors. The Audit Committee delegated to the Audit Chair the authority to pre-approve non-audit services, provided that the Chair reports to the Audit Committee at the next scheduled meeting such pre-approval and the Chair complies with such other procedures as may be established by our Audit Committee from time to time.

External Auditor Service Fees

Audit Fees

PricewaterhouseCoopers LLP are our auditors. PricewaterhouseCoopers LLP have been our auditors since October 2009. Fees we incurred with PricewaterhouseCoopers LLP for audit and non-audit services in the last two fiscal years are outlined in the following table.

Nature of Services	Fees Paid to Auditor in Year Ended December 31, 2016 ($)	Fees Paid to Auditor in Year Ended December 31, 2015 ($)
Audit Fees (1)	281,000	255,000
Audit-Related Fees (2)	21,000	-
Tax Fees (3)	45,000	95,900
All Other Fees (4)	170,000	43,000
Total	517,000	393,900

Notes:

(1) "Audit Fees" include fees necessary to perform the annual audit and quarterly reviews of our consolidated financial statements. Audit Fees include fees for review of tax provisions and for accounting consultations on matters reflected in the financial statements. Audit Fees also include audit or other attest services required by legislation or regulation, such as comfort letters, consents, reviews of securities filings and statutory audits.

(2) "Audit-Related Fees" for assurance and related services that are reasonably related to the performance of the audit or review of our consolidated financial statements and are not reported as audit fees. Services provided in this category include due diligence assistance, and accounting consultations on proposed transactions.

(3) "Tax Fees" include fees for all tax services other than those included in "Audit Fees" and "Audit-Related Fees". This category includes fees for tax compliance, tax planning and tax advice.

(4) "All Other Fees" include all other non-audit services.

Reliance on Exemptions

At no time since the commencement of our most recently completed financial year have we relied on any of the exemptions contained in National Instrument 52-110 – *Audit Committees* with respect to independence or composition of our Audit Committee.

Audit Committee Oversight

At no time since commencement to the most recently completed financial year has a recommendation of the Audit Committee to nominate or compensate an external auditor not been adopted by our Board of Directors.

DIVIDEND POLICY

Dividends and Dividend Policy

Cash dividends are made on the 15th day (or if such date is not a business day, on the next business day) following the end of each calendar month to Shareholders of record on the last business day of each such calendar month or such other date as determined from time to time by us. Unless otherwise specified, all dividends paid or to be paid by us are designated as "eligible dividends" under the *Income Tax Act* (Canada).

The following monthly cash dividends on our Common Shares were declared by us for the periods indicated below:

Date Range	Cash Dividend per Common Share
April 2016 to February 2017	$0.0233
February 2016 to March 2016	$0.0375
May 2014 to January 2016	$0.0625
January 2014 to April 2014	$0.0567
October 2013 to December 2013	$0.0525
January 2013 to September 2013	$0.0500

We carefully monitor the impact of all issues affecting our business and, the necessity to adjust our monthly dividends and our capital programs as conditions evolve. Dividends will normally be pre-approved on a quarterly basis in the context of prevailing and anticipated commodity prices and reconfirmed when declared. During periods of volatile commodity prices, we may vary the dividend rate monthly. See "*General Development of our Business – Developments in 2016*."

Our long term objective is to set our dividend policy at prudent levels while withholding sufficient funds to finance capital expenditures required to grow our current production base. This in turn, is expected to provide a stronger base of cash flow leading to consistent dividends into the future. Our dividend policy is reviewed monthly and is based on a number of factors including current and future commodity prices, foreign exchange rates, our commodity hedging program, current operations and available investment opportunities.

Our Credit Facility and Senior Secured Notes contain restrictions on our ability to pay dividends in certain circumstances. In addition, the payment of dividends by a corporation is governed by the liquidity and insolvency tests described in the *Business Corporations Act* (Alberta). Pursuant to the *Business Corporations Act* (Alberta), after the payment of a dividend, we must be able to pay our liabilities as they become due and the realizable value of our assets must be greater than our liabilities and the legal stated capital of our outstanding securities.

Cash dividends are not guaranteed. Our historical cash dividends may not be reflective of future cash dividends, which will be subject to review by our Board of Directors taking into account our prevailing financial circumstances at the relevant time. Although we intend to make dividends of our available cash to Shareholders, these cash dividends may be reduced or suspended. The actual amount distributed will depend on numerous factors and conditions existing from time to time, including fluctuations in commodity prices, production levels, capital expenditure requirements, debt service requirements, operating costs, royalty burdens, foreign exchange rates and the satisfaction of solvency tests imposed by the *Business Corporations Act* (Alberta) for the declaration and payment of dividends applicable law and other factors beyond our control. See "*Risk Factors – Dividends*".

INDUSTRY CONDITIONS

Companies operating in the oil and natural gas industry are subject to extensive regulation and control of operations (including land tenure, exploration, development, production, refining and upgrading, transportation, and marketing) as a result of legislation enacted by various levels of government with respect to the pricing and taxation of oil and natural gas, including the governments of Canada, Alberta, British Columbia and Saskatchewan, all of which should be carefully considered by investors in the oil and gas industry. It is not expected that any of these regulations or controls will affect our operations in a manner materially different than they will affect other oil and natural gas companies of similar size. All current legislation is a matter of public record and we are unable to predict what additional legislation or amendments governments may enact in the future. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and 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, prices are also influenced by regional market and transportation issues. 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. 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 National Energy Board of Canada. The National Energy Board of Canada 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) 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 National Energy Board of Canada 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 National Energy Board of Canada 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 a National Energy Board of Canada 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 National Energy Board of Canada.

The North American Free Trade Agreement

The North American Free Trade Agreement 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. The North American Free Trade Agreement 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. The North American Free Trade Agreement 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 the North American Free Trade Agreement, the impact of which on the oil and gas industry is uncertain.

Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations that govern royalties, production rates and other matters. The royalty regime in a given province is a significant factor in the profitability of oil sands projects, crude oil, natural gas liquids, sulphur and natural gas production. Royalties payable on production from lands where the Crown does not hold the mineral rights are determined by negotiation between the mineral freehold owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Royalties from production on Crown lands are determined by governmental regulation and are generally calculated as a percentage of the value of gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery and the type or quality of the petroleum product produced. Other royalties and royalty-like interests are carved out of the working interest owner's interest, from time to time, through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests or net carried interests.

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

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

Alberta

In Alberta, the Crown owns 81% 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 natural gas liquids), eliminating the need to label a well as "oil" or "gas". Post-payout, the Mid-Life phase will apply a higher royalty rate than the Pre-Payout phase. Depending on the commodity price of the substance the well is producing, the royalty rate could range from 5% - 40%. The metrics for calculating the Mid-Life phase royalty are based on commodity prices and are intended, on average, to yield the same internal rate of return as under the Alberta Royalty Framework. In the Mature phase of the MRF, once a well reaches the tail end of its cycle and production falls below a Maturity Threshold, currently the equivalent of 194 m^3 (40 barrels of oil equivalent per day 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.

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 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 Innovative Energy Technologies Program 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.

British Columbia

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

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

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

As of January 1, 2017, all liquid natural gas facilities are subject to a 3.5% income tax. This income tax is scheduled to increase to 5% in 2037. During the period in which net operating losses and capital investment are deducted, a tax rate of 1.5% will apply to the taxpayer's net income. Once the net operating losses and capital investment have been depleted, the full rate of 3.5% is payable. To encourage investment, the Government of British Columbia will offer a corporate income tax credit to any liquid natural gas taxpayer based on the amount of liquid natural gas acquired for a liquid natural gas facility.

The Government of British Columbia maintains a number of targeted royalty programs for key resource areas intended to increase the competitiveness of British Columbia's low productivity natural gas wells. These include both royalty credit and royalty reduction programs, including the following:

- *Deep Well Royalty Credit Program* providing a royalty credit for natural gas wells defined in terms of a dollar amount applied against royalties, is well specific and applies to drilling and completion costs for vertical wells with a true vertical depth greater than 2,500 metres and horizontal wells with a true vertical depth greater than 1,900 metres (or 2,300 metres if spud before September 1, 2009) and if certain other criteria are met, is intended to reflect the higher drilling and completion costs. Effective April 1, 2014, there are two tiers to the Deep Well Royalty Credit Program, "tier one" and "tier two". The pre-existing Deep Well Royalty Credit Program, as described above, will comprise tier two of the program. Tier one of the Deep Well Royalty Credit Program applies to shallower horizontal wells with a true vertical depth less than or equal to 1,900 metres if spud after March 31, 2014. Currently all wells that qualify for the tier one royalty credits are subject to a minimum royalty of 6% while wells that qualify for the tier two royalty credits are subject to a minimum royalty of 3%. These minimum royalty amounts apply when the net royalty payable would otherwise be zero for a production month;

- *Deep Re-Entry Royalty Credit Program* providing a royalty credit for deep re-entry wells with a true vertical depth to the top of pay if the re-entry well event is greater than 2,300 metres and a re-entry date after November 30, 2003; or if the well was spud on or after January 1, 2009, with a true vertical depth to the completion point of the re-entry well event being greater than 2,300 metres;

- *Deep Discovery Royalty Credit Program* providing the lesser of a 3-year royalty holiday or 283,000,000 m^3 of royalty free gas for deep discovery wells with a true vertical depth greater than 4,000 metres whose surface locations are at least 20 kilometres away from the surface location of any well drilled into a recognized pool within the same formation;

- *Coalbed Gas Royalty Reduction and Credit Program* providing a royalty reduction for coalbed gas wells with average daily production less than 17,000 m^3 as well as a royalty credit for coalbed gas wells equal to $50,000 for wells drilled on Crown land and a tax credit equal to $30,000 for wells drilled on freehold land;

- *Marginal Royalty Reduction Program* providing a monthly royalty reduction for low productivity natural gas wells with an average daily rate of production less than 23 m^3 for every metre of marginal well depth in the first 12 months of production. To be eligible, wells must have been spudded after May 31, 1998 and the first month of marketable gas production must have occurred between June 2003 and August 2008. Once a well passes the initial eligibility test, a reduction is realized in each month that average daily production is less than 25,000m^3;

- *Ultra-Marginal Royalty Reduction Program* providing royalty reductions for low productivity, shallow natural gas wells. Vertical wells must be less than 2,500 metres and horizontal wells less than 2,300 metres to be eligible. Production in the first 12 months ending after January 2007 must be less than 17m^3 per metre of depth for exploratory wildcat wells and less than 11m^3 per metre of depth for development wells and exploratory outpost wells. The well must have been spudded or re-entered after December 31, 2005. A reduction is realized in each month that average daily production is less than 60,000m^3. Horizontal wells that are spud on or after April 1, 2014 are not eligible for the Ultra-Marginal Royalty Reduction Program due to the potential for overlap with shallower horizontal wells eligible for a royalty credit under the Deep Well Royalty Credit Program; and

- *Net Profit Royalty Reduction Program* providing reduced initial royalty rates to facilitate the development and commercialization of technically complex resources such as coalbed gas, tight gas, shale gas and enhanced-recovery projects, with higher royalty rates applied once capital costs have been recovered.

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

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

Saskatchewan

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

A Resource Surcharge on the value of sales of oil, natural gas, potash, uranium and coal in Saskatchewan is levied under authority of *The Corporation Capital Tax Act*. For resource corporations, the Resource Surcharge rate is 3% of the value of sales of all potash, uranium and coal produced in Saskatchewan, and oil and natural gas produced from wells drilled in Saskatchewan prior to October 1, 2002. For oil and natural gas produced from wells drilled in Saskatchewan after September 30, 2002, the Resource Surcharge rate is 1.7% of the value of sales. The Resource Surcharge applies to resource trusts in addition to resource corporations. In addition, a mineral rights tax is charged to owners of mineral rights paid on an annual basis at the rate of $1.50 per acre owned.

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

- Heavy oil is classified as third tier oil (produced from a vertical well having a finished drilling date on or after January 1, 1994 and before October 1, 2002 or incremental oil from new or expanded waterflood projects with a commencement date on or after January 1, 1994 and before October 1, 2002), fourth tier oil (having a finished drilling date on or after October 1, 2002 or incremental oil from new or expanded waterflood projects with a commencement date on or after October 1, 2002) or new oil (conventional oil that is not classified as third tier oil or fourth tier oil).

- Southwest designated oil uses the same definition of fourth tier oil but third tier oil is defined as conventional oil produced from a vertical well having a finished drilling date on or after February 9, 1998 and before October 1, 2002 or incremental oil from new or expanded waterflood projects with a commencement date on or after February 9, 1998 and before October 1, 2002 and new oil is defined as conventional oil produced from a horizontal well having a finished drilling date on or after February 9, 1998 and before October 1, 2002.

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

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

Base prices are used to establish lower limits in the price-sensitive royalty structure for conventional oil and apply at a reference well production rate of 100 m^3 for old oil, new oil and third tier oil, and 250 m^3 per month for fourth tier oil. Where average wellhead prices are below the established base prices of $100 per m^3 for third and fourth tier oil and \$50 per m^3 for new oil and old oil, base royalty rates are applied. Base royalty rates are 5% for all fourth tier oil, 10% for heavy oil that is third tier oil or new oil, 12.5% for southwest designated oil that is third tier oil or new oil, 15% for non-heavy oil other than southwest designated oil that is third tier or new oil, and 20% for old oil. Where average wellhead prices are above base prices, marginal royalty rates are applied to the proportion of production that is above the base oil price. Marginal royalty rates are 30% for all fourth tier oil, 25% for heavy oil that is third tier oil or new oil, 35% for southwest designated oil that is third tier oil or new oil, 35% for non-heavy oil other than southwest designated oil that is third tier or new oil, and 45% for old oil.

The amount payable as a Crown royalty or a freehold production tax in respect of natural gas production is determined by a sliding scale based on the monthly provincial average gas price published by the Government of Saskatchewan, the quantity produced in a given month, the type of natural gas and the classification of the natural gas. Like conventional oil, natural gas may be classified as "non-associated gas" (gas produced from gas wells) or "associated gas" (gas produced from oil wells) and royalty rates are determined according to the finished drilling date of the respective well. Non-associated gas is classified as new gas (having a finished drilling date before February 9, 1998 with a first production date on or after October 1, 1976), third tier gas (having a finished drilling date on or after February 9, 1998 and before October 1, 2002), fourth tier gas (having a finished drilling date on or after October 1, 2002) and old gas (not classified as either third tier, fourth tier or new gas). A similar classification is used for associated gas except that the classification of old gas is not used, the definition of fourth tier gas also includes production from oil wells with a finished drilling date prior to October 1, 2002, where the individual oil well has a gas-oil production ratio in any month of at least 3,500 m^3 of gas for every m^3 of oil and new gas is defined as oil produced from a well with a finished drilling date before February 9, 1998 that received special approval, prior to October 1, 2002, to produce oil and gas concurrently without gas-oil ratio penalties.

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

As with conventional oil production, base prices based on a well reference rate of 250,000 m^3 per month are used to establish lower limits in the price-sensitive royalty structure for natural gas. Where average field-gate prices are below the established base prices of \$1.35 per GJ for third and fourth tier gas and \$0.95 per GJ for new gas and old gas, base royalty rates are applied. Base royalty rates are 5% for all fourth tier gas, 15% for third tier or new gas, and 20% for old gas. Where average wellhead prices are above base prices, marginal royalty rates are applied to the proportion of production that is above the base gas price. Marginal royalty rates are 30% for all fourth tier gas, 35% for third tier and new gas, and 45% for old gas**.** The current regulatory scheme provides for **c**ertain differences with respect to the administration of fourth tier gas, which is associated gas.

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

- *Royalty/Tax Incentive Volumes for Vertical Oil Wells Drilled on or after October 1, 2002* providing reduced Crown royalty (a Crown royalty rate of the lesser of fourth tier oil Crown royalty rate and 2.5%) and freehold tax rates (a freehold production tax rate of 0%) on incentive volumes of 8,000 m^3 for deep development vertical oil wells, 4,000 m^3 for non-deep exploratory vertical oil wells and 16,000 m^3 for deep exploratory vertical oil wells (more than 1,700 metres or within certain formations) and after the incentive volume is produced, the oil produced will be subject to the fourth tier royalty tax rate;

- *Royalty/Tax Incentive Volumes for Exploratory Gas Wells Drilled on or after October 1, 2002* providing reduced Crown royalty (a Crown royalty rate of the lesser of fourth tier oil Crown royalty rate and 2.5%) and freehold tax rates (a freehold production tax rate of 0%) on incentive volumes of 25,000,000 m^3 for qualifying exploratory gas wells;

- *Royalty/Tax Incentive Volumes for Horizontal Oil Wells Drilled on or after October 1, 2002* providing reduced Crown royalty (a Crown royalty rate of the lesser of fourth tier oil Crown royalty rate and 2.5%) and freehold tax rates (a freehold production tax rate of 0%) on incentive volumes of 6,000 m^3 for non-deep horizontal oil wells and 16,000 m^3 for deep horizontal oil wells (more than 1,700 metres total vertical depth or within certain formations) and after the incentive volume is produced, the oil produced will be subject to the fourth tier royalty tax rate;

- *Royalty/Tax Incentive Volumes for Horizontal Gas Wells drilled on or after June 1, 2010 and before April 1, 2013* providing for a classification of the well as a qualifying exploratory gas well and resulting in a reduced Crown royalty (a Crown royalty rate of the lesser of fourth tier oil Crown royalty rate and 2.5%) and freehold tax rates (a freehold production tax rate of 0%) on incentive volumes of 25,000,000 m^3 for horizontal gas wells and after the incentive volume is produced, the gas produced will be subject to the fourth tier royalty tax rate;

- Royalty/Tax Regime for Incremental Oil Produced from New or Expanded Waterflood Projects Implemented on or after October 1, 2002 whereby incremental production from approved waterflood projects is treated as fourth tier oil for the purposes of Crown royalty and freehold tax calculations;

- *Royalty/Tax Regime for Enhanced Oil Recovery Projects (Excluding Waterflood Projects) Commencing prior to April 1, 2005* providing lower Crown royalty and freehold tax determinations based in part on the profitability of enhanced oil recovery projects during and subsequent to the payout of the enhanced oil recovery operations;

- *Royalty/Tax Regime for Enhanced Oil Recovery Projects (Excluding Waterflood Projects) Commencing on or after April 1, 2005* providing a Crown royalty of 1% of gross revenues on enhanced oil recovery projects pre-payout and 20% of enhanced oil recovery operating income post-payout and a freehold production tax of 0% pre-payout and 8% post-payout on operating income from enhanced oil recovery projects; and

- *Royalty/Tax Regime for High Water-Cut Oil Wells* designed to extend the product lives and improve the recovery rates of high water-cut oil wells and granting third tier oil royalty/tax rates with a Saskatchewan Resource Credit of 2.5% for oil produced prior to April 2013 and 2.25% for oil produced on or after April 1, 2013 to incremental high water-cut oil production resulting from qualifying investments made to rejuvenate eligible oil wells and/or associated facilities.

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

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

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, we 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 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 *Jobs, Growth and Long-term Prosperity Act* (Canada), 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 *Jobs, Growth and Long-term Prosperity Act* (Canada) 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 National Energy Board of Canada, 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 liquid natural gas 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 Alberta Energy Regulator is the single regulator responsible for all energy development in Alberta. The Alberta Energy Regulator 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 Alberta Energy Regulator'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. The Integrated Resource Management System 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 Alberta Energy Regulator 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 Alberta Land Use Framework 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* provides the legislative authority for the Government of Alberta to implement the policies contained in the Alberta Land Use Framework. Regional plans established under the *Alberta Land Stewardship Act* 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 *Alberta Land Stewardship Act* 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 *Alberta Land Stewardship Act* 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 *Alberta Land Stewardship Act* 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 which came into force on September 1, 2012. The Lower Athabasca Regional Plan is the first of seven regional plans developed under the Alberta Land Use Framework. Lower Athabasca Regional Plan 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.

The Lower Athabasca Regional Plan 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 which came into force on September 1, 2014. The South Saskatchewan Regional Plan is the second regional plan developed under the Alberta Land Use Framework. The South Saskatchewan Regional Plan covers approximately 83,764 square kilometres and includes 44% of the provincial population.

The South Saskatchewan Regional Plan creates four new and four expanded conservation areas, and two new and six expanded provincial parks and recreational areas. Similar to Lower Athabasca Regional Plan, the South Saskatchewan Regional Plan 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 has been completed and the Regional Advisory Council is currently preparing its Recommendation to Government report. The North Saskatchewan Region Plan 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.

British Columbia

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

Saskatchewan

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

Liability Management Rating Programs

Alberta

In Alberta, the Alberta Energy Regulator administers the Licensee Liability Rating Program. The Licensee Liability Rating Program is a liability management program governing most conventional upstream oil and gas wells, facilities and pipelines. Alberta's *Oil and Gas Conservation Act* 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 Licensee Liability Rating Program if a licensee or working interest participant becomes defunct or is unable to meet its obligations. The Orphan Fund is funded by licensees in the Licensee Liability Rating Program through a levy administered by the Alberta Energy Regulator. The Licensee Liability Rating 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 Licensee Liability Rating Program requires a licensee whose deemed liabilities exceed its deemed assets to provide the Alberta Energy Regulator 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 Alberta Energy Regulator. The Alberta Energy Regulator 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 Alberta Energy Regulator implemented important changes to the Licensee Liability Rating Program 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 Licensee Liability Rating 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 Alberta Energy Regulator 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 Alberta's *Oil and Gas Conservation Act* and the *Bankruptcy and Insolvency Act*, and that receivers and trustees have the right to renounce assets within insolvency proceedings. Such a conflict renders the Alberta Energy Regulator'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 Fund or the province in these instances because any resources of the insolvent licensee will first be used to satisfy secured creditors under the

Bankruptcy and Insolvency Act. *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 Alberta Energy Regulator 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 Alberta Energy Regulator 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 Alberta Energy Regulator licences, approvals, and permits, the Alberta Energy Regulator will require all transferees to demonstrate that they have a liability management rating, 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 Alberta Energy Regulator 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 a liability management rating 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 Alberta Energy Regulator with additional flexibility to permit licensees to acquire additional Alberta Energy Regulator-licensed assets if:

1. The licensee already has a liability management rating of 2.0 or higher;
2. The acquisition will improve the licensee's liability management rating to 2.0 or higher; or
3. The licensee is able to satisfy its obligations, notwithstanding an liability management rating below 2.0, by other means.

The Alberta Energy Regulator 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 Alberta Energy Regulator, despite a transferee's liability management rating 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 Alberta Energy Regulator implemented the Inactive Well Compliance Program to address the growing inventory of inactive wells in Alberta and to increase the Alberta Energy Regulator's surveillance and compliance efforts under *Directive 013: Suspension Requirements for Wells.* The inactive well compliance program 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 inactive well compliance program 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 inactive well compliance program is available on the Alberta Energy Regulator's Digital Data Submission system. The Alberta Energy Regulator has announced that from April 1, 2015 to April 1, 2016, the number of noncompliant wells subject to the Inactive Well Compliance Program fell from 25,792 to 17,470, with 76% of licensees operating in the province having met their annual quota.

British Columbia

In British Columbia, the Commission oversees the Liability Management Rating Program ("**LMR Program**"), designed to manage public liability exposure related to oil and gas activities by ensuring that permit holders carry the financial risks and regulatory responsibility of their operations through to regulatory closure. Under the LMR Program, the Commission determines the required security deposits for permit holders under the *Oil and Gas Activities Act*. The LMR is the ratio of a permit holder's deemed assets to deemed liabilities. Permit holders whose deemed liabilities exceed deemed assets will be considered high risk and reviewed for a security deposit. Permit holders who fail to submit the required security deposit within the allotted timeframe may be in non-compliance with the *Oil and Gas Activities Act*.

Saskatchewan

In Saskatchewan, the Ministry of the Economy administrates the Licensee Liability Rating Program. The Licensee Liability Rating Program is designed to assess and manage the financial risk that a licensee's well and facility abandonment and reclamation liabilities pose to an orphan fund (the "**Oil and Gas Orphan Fund**") established under *The Oil and Gas Conservation Act*. The Oil and Gas Orphan Fund is responsible for carrying out the abandonment and reclamation of wells and facilities contained within the Licensee Liability Rating Program when a licensee or working interest participant is defunct or missing. The Licensee Liability Rating Program requires a licensee whose deemed liabilities exceed its deemed assets to post a security deposit. The ratio of deemed assets to liabilitiesis assessed once each month for all licensees of oil, gas and service wells and upstream oil and gas facilities. On August 19, 2016, the Ministry of the Economy released a notice to all operators that it would follow the Alberta Energy Regulator's interim rules by processing all licence transfer applications as non-routine until further notice.

Climate Change Regulation

Federal

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

On April 26, 2007, the Government of Canada released "Turning the Corner: An Action Plan to Reduce Greenhouse Gases and Air Pollution" (the "**Action Plan**") which set forth a plan for regulations to address both greenhouse gas 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 greenhouse gas emissions from 2005 levels by 2020; however, the greenhouse gas emission reduction targets are not binding. In May 2015, Canada submitted its Intended Nationally Determined Contribution to the UNFCCC. Intended Nationally Determined Contributions 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 Intended Nationally Determined Contribution became its Nationally Determined Contributions. As a result, the Government of Canada replaced its Intended Nationally Determined Contribution of a 17% reduction target established in the Copenhagen Accord with a Nationally Determined Contribution 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 our operations and cash flow.

Alberta

As part of its efforts to reduce greenhouse gas emissions, Alberta introduced legislation to address greenhouse gas emissions: the *Climate Change and Emissions Management Act* 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*, which imposes greenhouse gas limits, and the *Specified Gas Reporting Regulation*, which imposes greenhouse gas emissions reporting requirements. Alberta is the first jurisdiction in North America to impose regulations requiring large facilities in various sectors to reduce their greenhouse gas emissions.

The *Specified Gas Emitters Regulation*, effective July 1, 2007, applies to facilities emitting more than 100,000 tonnes of greenhouse gases emissions in 2003 or any subsequent year ("**Regulated Emitters**"), and requires reductions in greenhouse gas emissions intensity (e.g. the quantity of greenhouse gas emissions per unit of production) from emissions intensity baselines established in accordance with the *Specified Gas Emitters Regulation*.

On June 25, 2015, the Government of Alberta renewed the *Specified Gas Emitters Regulation* 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. Contributions to the fund are made at a rate of $15 per tonne of greenhouse gas emissions, increasing to a rate of $20 per tonne of greenhouse gas emissions in 2016 and $30 per tonne of greenhouse gas 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* was passed into law. The *Climate Leadership Implementation Act* enacted the *Climate Leadership Act* introducing a carbon tax on all sources of greenhouse gas 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 *Specified Gas Emitters Regulation* 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 *Specified Gas Emitters Regulation*, 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 greenhouse gas 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 *Climate Leadership Implementation Act* is the first step towards executing the Climate Leadership Plan (other legislation is still pending). In addition to enacting the *Climate Leadership Act*, the *Climate Leadership Implementation Act* 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.

British Columbia

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

Further, on April 3, 2008, the Government of British Columbia introduced the *Greenhouse Gas Reduction (Cap and Trade) Act* (the "**Cap and Trade Act**"), which received royal assent on May 29, 2008 and partially came into force by regulation of the Lieutenant Governor in Council. It sets a province-wide target of a 33% reduction in the 2007 level of greenhouse gas emissions by 2020 and an 80% reduction by 2050. Unlike the emissions intensity approach taken by the federal government and the Alberta government, the *Cap and Trade Act* establishes an absolute cap on greenhouse gas emissions.

The *Greenhouse Gas Emission Reporting Regulation*, implemented under the authority of the Cap and Trade Act, set out the requirements for the reporting of the GHG emissions from facilities in British Columbia emitting 10,000 tonnes or more of carbon dioxide equivalent emissions per year beginning on January 1, 2010. Those reporting operations with emissions of 25,000 tonnes or greater are required to have emissions reports verified by a third party. The reporting system for large emitters of greenhouse gases has since been streamlined by the *Greenhouse Gas Industrial Reporting and Control Act* and its associated regulations that came into force on January 1, 2016. The *Greenhouse Gas Industrial Reporting and Control Act* sets out benchmarked performance standards for different industrial facilities and sectors, provides for emissions offsets through the purchase of emission credits or emission offsetting projects, among other measures, and replaces the *Cap and Trade Act*.

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

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

Saskatchewan

On May 11, 2009, the Government of Saskatchewan announced *The Management and Reduction of Greenhouse Gases Act* to regulate greenhouse gas emissions in the province. The *Management and Reduction of Greenhouse Gases Act* received Royal Assent on May 20, 2010 and will come into force on proclamation. The *Management and Reduction of Greenhouse Gases Act* establishes a framework for achieving the provincial target of a 20% reduction in greenhouse gas emissions from 2006 levels by 2020. Although, the *Management and Reduction of Greenhouse Gases Act* and related regulations have yet to be proclaimed in force, draft versions indicate that the Government of Saskatchewan will permit the use of pre-certified investment credits, early action credits and emissions offsets in compliance, similar to the federal climate change initiatives. It remains unclear whether the scheme implemented by the *Management and Reduction of Greenhouse Gases Act* will be based on emissions intensity or an absolute cap on emissions.

RISK FACTORS

Investors should carefully consider the risk factors set out below and consider all other information contained herein and in our 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 our 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. Our long-term commercial success depends on our ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, our existing reserves, and the production from them, will decline over time as we produce from such reserves. A future increase in our reserves will depend on both our ability to explore and develop our existing properties and on our ability to select and acquire suitable producing properties or prospects. There is no assurance that we will be able continue to find satisfactory properties to acquire or participate in. Moreover, our management may determine that current markets, terms of acquisition, participation or pricing conditions make potential acquisitions or participation uneconomic. There is also no assurance that we will discover or acquire further commercial quantities of oil and natural gas.

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

Drilling hazards, environmental damage and various field operating conditions could greatly increase the cost of operations and adversely affect the production from successful wells. Field operating conditions include, but are not limited to, delays in obtaining governmental approvals or consents, 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, we may explore for and produce sour natural gas in certain areas. An unintentional leak of sour natural gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability to us.

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

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

Weakness in the Oil and 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, slowing growth in China and other 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 our reserves, rendering certain reserves uneconomic. In addition, lower commodity prices have restricted, and are anticipated to continue to restrict, our cash flow resulting in a reduced capital expenditure budget. As a result, we may not be able to replace our production with additional reserves and both our production and reserves could be reduced on a year over year basis. Any decrease in value of our reserves may reduce the borrowing base under our Credit Facility, which, depending on the level of our indebtedness, could result in having to repay a portion of our indebtedness. Given the current market conditions and the lack of confidence in the Canadian oil and gas industry, we may have difficulty raising additional funds or if we are able to do so, it may be on unfavourable and highly dilutive terms. If these conditions persist, our cash flow may not be sufficient to continue to fund our operations and to satisfy our obligations when due and will require additional equity or debt financing and/or proceeds from asset sales. There can be no assurance that such equity or debt financing will be available on terms that are satisfactory or at all. Similarly, there can be no assurance that we will be able to realize any or sufficient proceeds from asset sales to discharge our obligations.

Prices, Markets and Marketing

Numerous factors beyond our control do, and will continue to affect the marketability and price of oil and natural gas acquired, produced, or discovered by us. Our ability to market our oil and natural gas may depend upon our 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 that our 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 us.

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 our control. These factors include economic and political conditions, in the United States, Canada, Europe China and emerging markets, the actions of the Organization of the Petroleum Exporting Countries, 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 our 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 and the Organization of the Petroleum Exporting Countries recent decisions pertaining to the oil production of member countries and non-member countries' decisions on production levels, among other factors. A material decline in prices could result in a reduction of our 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 our reserves. We might also elect not to produce from certain wells at lower prices.

All these factors could result in a material decrease in our expected net production revenue and a reduction in our oil and natural gas acquisition, development and exploration activities. Any substantial and extended decline in the price of oil and natural gas would have an adverse effect on the carrying value of our assets and reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on our 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, the Organization of the Petroleum Exporting Countries 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 our Common Shares

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

Dividends

The amount of future cash dividends paid by us, if any, will be subject to the discretion of our Board of Directors and may vary depending on a variety of factors and conditions existing from time to time, including fluctuations in commodity prices, production levels, capital expenditure requirements, debt service requirements, operating costs, royalty burdens, foreign exchange rates and the satisfaction of the liquidity and solvency tests imposed by the *Business Corporations Act* (Alberta) for the declaration and payment of dividends. Depending on these and various other factors, many of which will be beyond our control, our dividend policy may vary from time to time and, as a result, future cash dividends could be reduced or suspended entirely.

The market value of our Common Shares may deteriorate if dividends are reduced or suspended. Furthermore, the future treatment of dividends for tax purposes will be subject to the nature and composition of dividends paid by us and potential legislative and regulatory changes. Dividends may be reduced during periods of lower revenues, which result from lower commodity prices and any decision by us to finance capital expenditures using available capital.

To the extent that external sources of capital, including the issuance of additional Common Shares, become limited or unavailable, our ability to make the necessary capital investments to maintain or expand petroleum and natural gas reserves and to invest in assets, as the case may be, will be impaired. To the extent that we are required to use available capital to finance capital expenditures or property acquisitions, the cash available for dividends may be reduced.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

We consider 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 our ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with ours. 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 that we can focus our efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain of our non-core assets, if disposed of, may realize less on disposition than their carrying value on our consolidated financial statements.

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 us.

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 our ability to market our products internationally, increase costs for goods and services required for our operations, reduce access to skilled labour and negatively impact our business, operations, financial conditions and the market value of our Common Shares.

Operational Dependence

Other companies operate some of the assets in which we have an interest. We have limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect our financial performance. Our return on assets operated by others depends upon a number of factors that may be outside of our 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 we 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 we have an interest fail to satisfy regulatory requirements with respect to abandonment and reclamation obligations we may be required to satisfy such obligations and to seek reimbursement from such companies. To the extent that any of such companies go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency, it could result in such assets being shut-in, the potential of us becoming subject to additional liabilities relating to such assets and us having difficulty collecting revenue due from such operators or recovering amounts owing to us from such operators for their share of abandonment and reclamation obligations. Any of these factors could materially adversely affect our financial and operational results.

Project Risks

We manage a variety of small and large projects in the conduct of our business. Project delays may delay expected revenues from operations. Significant project cost overruns could make a project uneconomic. Our ability to execute projects and market oil and natural gas depends upon numerous factors beyond our control, including:

- the availability of processing capacity;
- the availability and proximity of pipeline capacity;
- the availability of storage capacity;
- the availability of, and the ability to acquire, water supplies needed for drilling, hydraulic fracturing and waterfloods or our ability to dispose of water used or removed from strata at a reasonable cost and in accordance with applicable environmental regulations;
- the effects of inclement weather;
- the availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- 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, we could be unable to execute projects on time, on budget, or at all, and may be unable to market the oil and natural gas that we produce effectively.

Gathering and Processing Facilities, Pipeline Systems and Rail

We deliver our products through gathering, processing facilities and pipeline systems some of which we do not own and, in certain circumstances, by rail. The amount of oil and natural gas that we can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering and processing facilities, pipeline systems and railway lines. The lack of availability of capacity in any of the gathering and processing facilities, pipeline systems and railway lines could result in our inability to realize the full economic potential of our production or in a reduction of the price offered for our production. The lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to transport produced oil and gas to market. In addition, the pro-rationing of capacity on inter-provincial pipeline systems continues to affect the ability to export oil 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 our production, operations and financial results. As a result, producers are increasingly turning to rail as an alternative means of transportation. In recent years, the volume of crude oil shipped by rail in North America has increased dramatically. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays or uncertainty in constructing new infrastructure systems and facilities could harm our business and, in turn, our financial condition, results of operations and cash flows. In addition, the Federal Government has signaled that it plans to review the National Energy Board approval process for large federally regulated projects. This may cause the timeframe for project approvals to increase for current and future applications.

Following major accidents in Lac-Megantic, Quebec and North Dakota, the Transportation Safety Board of Canada and the U.S. National Transportation Board have recommended additional regulations for railway tank cars carrying crude oil. In June 2015, as a result of these recommendations, the Government of Canada passed the Safe and Accountable Rail Act which increased insurance obligations on the shipment of crude oil by rail 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 our production may, from time to time, be processed through facilities owned by third parties and 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 material adverse effect on our ability to process our production and to deliver the same for sale.

Competition

The petroleum industry is competitive in all of its phases. We compete with numerous other entities in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas. Our competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than ours. Our ability to increase our reserves in the future will depend not only on our ability to explore and develop our present properties, but also on our ability to select and acquire other suitable producing properties or prospects for exploratory drilling. Competitive factors in the distribution and marketing of oil and natural gas include price, methods, and reliability of delivery and storage.

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. If we implement such technologies, there is no assurance that we will do so successfully. One or more of the technologies currently utilized by us or implemented in the future may become obsolete. In such case, our business, financial condition and results of operations could be materially adversely affected. If we are unable to utilize the most advanced commercially available technology, or we are unsuccessful in implementing certain technologies, our business, financial condition and results of operations could be materially adversely affected.

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. We cannot predict the impact of changing demand for oil and natural gas products, and any major changes may have a material adverse effect on our business, financial condition, results of operations and cash flows.

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 our costs, either of which may have a material adverse effect on our business, financial condition, results of operations and prospects. In order to conduct oil and natural gas operations, we require regulatory permits, licenses, registrations, approvals and authorizations from various governmental authorities at the provincial and federal level. There can be no assurance that we will be able to obtain all of the permits, licenses, registrations, approvals and authorizations that may be required to conduct operations that we may wish to undertake. In addition, certain federal legislation such as the *Competition Act* (Canada) and the *Investment Canada Act* (Canada) could negatively affect our business, financial condition and the market of our Common Shares or our 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 our projects. An increase in royalties would reduce our earnings and could make future capital investments, or our 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 our costs of compliance and doing business as well as delay the development of oil and natural gas resources from shale formations, which are not commercial without the use of hydraulic fracturing. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves.

Waterflood

We undertake or intend to undertake certain waterflooding programs which involve the injection of water or other liquids into an oil reservoir to increase production from the reservoir and to decrease production declines. To undertake such waterflooding activities we need 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 we will have access to the required volumes of water. In addition, in certain areas there may be restrictions on water use for activities such as waterflooding. If we are unable to access such water it may not be able to undertake waterflooding activities, which may reduce the amount of oil and natural gas that we are ultimately able to produce from our reservoirs. In addition, we may undertake certain waterflood programs that ultimately prove unsuccessful in increasing production from the reservoir and as a result have a negative impact on our results of operations.

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 us to incur costs to remedy such discharge. Although we believe that we are 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 our 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 obligations. These programs generally involve an assessment of the ratio of a licensee's deemed assets to deemed liabilities. If a licensee's deemed liabilities exceed its deemed assets, a security deposit is required. Changes to the required ratio of our deemed assets to deemed liabilities or other changes to the requirements of liability management programs may result in significant increases to the our compliance requirement. In addition, the liability management system may prevent or interfere with our ability to acquire or dispose of assets as both the vendor and the purchaser of oil and gas assets must be in compliance with the liability management programs (both before and after the transfer of the assets) for the applicable regulatory agency to allow for the transfer of such assets. See, "*Industry Conditions – Liability Management Rating Programs*".

Climate Change

Our exploration and production facilities and other operations and activities emit greenhouse gases and which may require us to comply with greenhouse gas emissions legislation at the provincial or federal level. Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place. As a signatory to the *UNFCCC* and as 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 greenhouse gas emissions from 2005 levels by 2020, however, these greenhouse gas 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 greenhouse gas 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 greenhouse gas emissions. In addition, on January 1, 2017 the *Climate Leadership* Act came into effect in the Province of Alberta introducing a carbon tax on almost all sources of greenhouse gas 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 our business, financial condition, results of operations and prospects. Some of our significant facilities may ultimately be subject to future regional, provincial and/or federal climate change regulations to manage greenhouse gas 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 greenhouse gases and resulting requirements, it is not possible to predict the impact on us and our operations and financial condition. See "*Industry Conditions – Climate Change Regulation*".

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 our production revenues. Accordingly, exchange rates between Canada and the United States could affect the future value of our reserves. Although a low value of the Canadian dollar relative to the United States dollar may positively affect the price we receive for our oil and natural gas production, it could also result in an increase in the price for certain goods used for our operations, which may have a negative impact on our financial results**.**

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

An increase in interest rates could result in a significant increase in the amount we pay to service debt, resulting in a reduced amount available to fund our exploration and development activities, and if applicable, the cash available for dividends and could negatively impact the market price of our 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, our ability to do so is dependent on, among other factors:

- the overall state of the capital markets
- our credit rating (if applicable);
- commodity prices;
- interest rates;
- royalty rates;
- tax burden due to current and future tax laws; and
- investor appetite for investments in the energy industry and our 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 gas industry have negatively impacted the ability of oil and 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 us. We may be required to seek additional equity financing on terms that are highly dilutive to existing Shareholders. Our inability 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 our reserves may not be sufficient to fund our 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 us 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 gas industry and/or global economic and political volatility, we may from time to time have restricted access to capital and increased borrowing costs. The current conditions in the oil and gas industry have negatively impacted the ability of oil and gas companies to access additional financing.

As a result of global economic and political volatility, we may from time to time have restricted access to capital and increased borrowing costs. Failure to obtain such financing on a timely basis could cause us to forfeit our interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If our revenues from our reserves decrease as a result of lower oil and natural gas prices or otherwise, it will 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 our 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 our capital expenditure plans may result in a delay in development or production on our properties.

Credit Facility Arrangements

We currently have a credit facility and the amount authorized thereunder is dependent on the borrowing base determined by our lenders. Our lenders use our 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 us under the Credit Facility which could result in the requirement to repay a portion, or all, of our bank indebtedness. We are required to comply with covenants under our Credit Facility 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, our access to capital could be restricted or repayment could be required. Events beyond our control may contribute to our failure to comply with such covenants. A failure to comply with covenants could result in the default under the Credit Facility, which could result in us 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, our Credit Facility may impose operating and financial restrictions on us in certain circumstances 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.

Issuance of Debt

From time to time, we may enter into transactions to acquire assets or shares of other entities. These transactions may be financed in whole or in part with 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 our 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 us from commodity price declines, we may also be prevented from realizing the full benefits of price increases above the levels of the derivative instruments used to manage price risk. In addition, our hedging arrangements may expose us to the risk of financial loss in certain circumstances, including instances in which:

- production falls short of the hedged volumes or 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 or 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, we will not benefit from the fluctuating exchange rate.

Availability of Drilling Equipment and Access

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment (typically leased from third parties) as well as skilled personnel trained to use such equipment in the areas where such activities will be conducted. Demand for such limited equipment and skilled personnel, or access restrictions, may affect the availability of such equipment and skilled personnel to us and may delay 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. Our actual interest in properties may vary accordingly from our records. If a title defect does exist, it is possible that we may lose all or a portion of the properties to which the title defect relates, which may have a material adverse effect on our business, financial condition, results of operations and prospects. There may be valid challenges to title, or proposed legislative changes which affect title, to the oil and natural gas properties we control that, if successful or made into law, could impair our activities on them and result in a reduction of the revenue received by us.

Reserve Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and natural gas liquids reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth in this Annual Information Form 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 thereof and such variations could be material.

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

In accordance with applicable securities laws, our 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 thus 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 us becoming subject to 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 us. 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 us. Conflicts, or conversely peaceful developments, arising outside of Canada, including changes in political regimes or the parties in power, 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, our 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

We may be subject to growth related risks including capacity constraints and pressure on our internal systems and controls. Our ability to manage growth effectively will require us to continue to implement and improve our operational and financial systems and to expand, train and manage our employee base. Our inability to deal with this growth may have a material adverse effect on our business, financial condition, results of operations and prospects.

Expiration of Licences and Leases

Our 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 fails 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.

Litigation

In the normal course of our operations, we may become involved in, named as a party to, or be the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions, 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 us and as a result, could have a material adverse effect on our assets, liabilities, business, financial condition and results of operations. Even if we prevail 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 affect on our financial condition.

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights in portions of Western Canada. We are not aware that any claims have been made in respect of our properties and assets. However, if a claim arose and was successful, such claim may have a material adverse effect on our business, financial condition, results of operations and prospects. In addition, the process of addressing such claims, regardless of the outcome, is expensive and time consuming and could result in delays which could have a material adverse effect on our business and financial results.

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 generally signed by third parties prior to the disclosure of any confidential information, a breach could put us at competitive risk and may cause significant damage to our business. The harm to our business from a breach of confidentiality cannot presently be quantified, but may be material and may not be compensable in damages. There is no assurance that, in the event of a breach of confidentiality, we will be able to obtain equitable remedies, such as injunctive relief, from a court of competent jurisdiction in a timely manner, if at all, in order to prevent or mitigate any damage to its business that such a breach of confidentiality may cause.

Income Taxes

We file all required income tax returns and believe that we are in full compliance with the provisions of the *Income Tax Act* (Canada) and all other applicable provincial tax legislation. However, such returns are subject to reassessment by the applicable taxation authority. In the event of a successful reassessment of us, whether by re-characterization of exploration and development expenditures or otherwise, such reassessment may have an impact on current and future taxes payable.

Income tax laws relating to the oil and 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 us. Furthermore, tax authorities having jurisdiction over us may disagree with how we calculate our income for tax purposes or could change administrative practices to our detriment.

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 rigs and other heavy equipment, thereby reducing activity levels. Certain oil and natural gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. In addition, extreme cold weather, heavy snowfall and heavy rainfall may restrict our ability to access our properties and cause operational difficulties. Seasonal factors and unexpected weather patterns may lead to declines in 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 to us, 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 our 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 us 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 *Business Corporations Act* (Alberta) 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 us 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 *Business Corporations Act* (Alberta). See "*Directors and Officers – Conflicts of Interest*".

Reliance on Key Personnel

Our 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 personnel insurance in effect. The contributions of the existing management team to our immediate and near term operations are likely to be of central importance. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that we will be able to continue to attract and retain all personnel necessary for the development and operation of our business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of our management.

Information Technology Systems and Cyber-Security

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

Further, we are subject to a variety of information technology and system risks as a part of our normal course operations, including potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach, and destruction or interruption of our information technology systems by third parties or insiders. Unauthorized access to these systems by employees or third parties could lead to corruption or exposure of confidential, fiduciary or proprietary information, interruption to communications or operations or disruption to our business activities or our competitive position. Further, disruption of critical information technology services, or breaches of information security, could have a negative effect on our performance and earnings, as well as on our reputation. We apply technical and process controls in line with industry-accepted standards to protect our information assets and systems;

however, these controls may not adequately prevent cyber-security breaches. The significance of any such event is difficult to quantify, but may in certain circumstances be material and could have a material adverse effect on our business, financial condition and results of operations.

Expansion into New Activities

Our operations and the expertise of our management are currently focused primarily on oil and 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 risks and uncertainties, of both a general and specific nature, that could cause actual results to differ materially from those suggested by the forward-looking 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 "*Forward-Looking Statements*" of this Annual Information Form.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

There are no legal proceedings that we are or were a party to, or that any of our property is or was the subject of, during our most recently completed financial year, that were or are material to us, and there are no such material legal proceedings that we are currently aware of that are contemplated.

There were no: (i) penalties or sanctions imposed against us by a court relating to securities legislation or by a security regulatory authority during the most recently completed financial year; (ii) other penalties or sanctions imposed by a court or regulatory body against us that would likely be considered important to a reasonable investor in making an investment decision; or (iii) settlement agreements we entered into before a court relating to securities legislation or with a securities regulatory authority during our most recently completed financial year.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, the only material contract entered into by us within the most recently completed financial year, or before the most recently completed financial year but which is still material and is in effect, are the agreements in respect of our Credit Facility, which are available on our SEDAR profile at *www.sedar.com*.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

There are no material interests, direct or indirect, of our directors and senior officers, or any holder of our Common Shares who beneficially owns, or controls or directs, directly or indirectly, more than 10% of our outstanding Common Shares, or any known associate or affiliate of such persons, in any transaction completed within the last three years or in any proposed transaction during the current financial year which have materially affected or are reasonably expected to materially affect us.

AUDITORS

PricewaterhouseCoopers LLP, Suite 3100, 111 – 5th Avenue S.W., Calgary, Alberta, T2P 5L3, is our auditor.

TRANSFER AGENT AND REGISTRAR

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

INTERESTS OF EXPERTS

We used PricewaterhouseCoopers LLP for external audit and tax advisory services for the fiscal year ended December 31, 2016. PricewaterhouseCoopers LLP has advised us that they are independent with respect to us within the meaning of the Rules of Professional Conduct of Chartered Professional Accountants of Alberta.

McDaniel prepared the McDaniel Report, a summary of which is contained in this Annual Information Form. In addition, this Annual Information Form makes reference to the Trident Report prepared by NSAI. None of the designated professionals of McDaniel or NSAI have any registered or beneficial interests, direct or indirect, in any of our securities or other property or of our associates or affiliates either at the time they prepared the statements, reports or valuations prepared by it, at any time thereafter or to be received by them.

In addition, none of the aforementioned persons or companies, nor any director, officer or employee of any of the aforementioned persons or companies, is or is expected to be elected, appointed or employed as a director, officer or employee of us or of any of our associates or affiliates, except for Grant A. Zawalsky, one of our directors, is a partner at Burnet, Duckworth & Palmer LLP, which law firm renders legal services to us.

ADDITIONAL INFORMATION

Additional information relating to us can be found on our SEDAR profile at *www.sedar.com* and on our website at www.wcap.ca. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of our securities and securities issued and authorized for issuance under our equity compensation plans will be contained in our proxy materials relating to our annual shareholders meeting to be held on April 28, 2017. Additional financial information is contained in our consolidated financial statements for the year ended December 31, 2016 and the related management's discussion and analysis.

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

Whitecap Resources Inc.
Suite 3800, 525 – 8 Avenue S.W.
Calgary, Alberta, T2P 1G1
Tel: (403) 266-0767
Fax: (403) 266-6975

APPENDIX A

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

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

An independent qualified reserves evaluator has evaluated Whitecap's reserves data. The report of the independent qualified reserves evaluator is presented below.

The Reserves Committee of the Board of Directors of Whitecap has:

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

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

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

The Reserves Committee of the Board of Directors has reviewed Whitecap's 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

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

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

(c) the content and filing of this report.

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

(signed) "*Grant B. Fagerheim*"
Grant B. Fagerheim
Chairman, President and Chief Executive Officer

(signed) "*Glenn A. McNamara*"
Glenn A. McNamara
Director, Chairman of the Reserves Committee and Member of the Compensation and Corporate Governance Committee

(signed) "*Darin Dunlop*"
Darin R. Dunlop
Vice President Engineering

(signed) "*Gregory S. Fletcher*"
Gregory S, Fletcher
Director and Member of the Audit Committee and the Reserves Committee

March 6, 2017

APPENDIX B

REPORTS ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATORS FORM 51-101F2

To the board of directors of Whitecap Resources Inc. (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.

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

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

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

Independent Qualified Reserves Evaluator	Effective Date of Evaluation Report	Location of Reserves (County or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate – $000s)			
			Audited	**Evaluated**	**Reviewed**	**Total**
McDaniel & Associates Consultants Ltd.	December 31, 2016	Canada	-	5,306,228	-	5,306,228

6. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied.

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

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

Executed as to our report referred to above:

McDaniel & Associates Consultants Ltd., Calgary, Alberta, Canada, February 16, 2017.

"ORIGINALLY SIGNED BY"
P. A. Welch, P. Eng.
President & Managing Director

APPENDIX B

REPORTS ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATORS FORM 51-101F2

To the board of directors of Trident Limited Partnership (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.

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

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

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

			Net Present Value of Future Net Revenue (before income taxes, 10% discount rate – $000s)			
Independent Qualified Reserves Evaluator	**Effective Date of Evaluation Report**	**Location of Reserves (County or Foreign Geographic Area)**	**Audited**	**Evaluated**	**Reviewed**	**Total**
Netherland, Sewell and Associates Inc.	December 31, 2016	Canada	-	274,038.9	-	274,038.9

6. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied.

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

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

Executed as to our report referred to above:

Netherland, Sewell and Associates Inc., Dallas, Texas, USA, February 3, 2017.

"ORIGINALLY SIGNED BY"
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

APPENDIX C

MANDATE & TERMS OF REFERENCE
OF THE
AUDIT COMMITTEE

Role and Objective

The Audit Committee (the "**Committee**") is a committee of the board of directors of Whitecap Resources Inc. ("**Whitecap**") to which the Board of Directors of Whitecap (the "**Board**") has delegated its responsibility for oversight of the nature and scope of the annual audit, management's reporting on internal accounting standards and practices, financial information and accounting systems and procedures, financial reporting and statements and recommending, for board of director approval, the audited financial statements and other mandatory disclosure releases containing financial information. The objectives of the Committee are as follows:

1. to assist directors meet their responsibilities (especially for accountability) in respect of the preparation and disclosure of the financial statements of Whitecap and related matters;

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

3. to enhance the external auditor's independence;

4. to review the credibility and objectivity of financial reports; and

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

Membership of Committee

1. The Committee shall be comprised of at least three (3) directors of Whitecap, none of whom are members of management of Whitecap and all of whom are "unrelated directors" (as such term is used in the Report of the Toronto Stock Exchange on Corporate Governance in Canada) and "independent" (as such term is used in National Instrument 52-110 - Audit Committees ("**NI 52-110**"). Provided that in the event that the common shares of Whitecap trade on the facilities of the TSX Venture Exchange, the Committee shall be comprised of at least three (3) directors of Whitecap, the majority of whom shall be "independent" (as such term is used in NI 52-110) in reliance of the exemptions afforded to venture issuers under NI 52-110.

2. The Board of Directors shall have the power to appoint the Committee Chairman, who shall be an unrelated director.

3. All of the members of the Committee shall be "financially literate". The Board of Directors of Whitecap has adopted the definition for "financial literacy" used in NI 52-110.

Meetings

1. At all meetings of the Committee every question shall be decided by a majority of the votes cast. In case of an equality of votes, the Chairman of the meeting shall not be entitled to a second or casting vote.

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

3. Meetings of the Committee should be scheduled to take place at least four times per year. Minutes of all meetings of the Committee shall be taken and shall be made available to the board. The Chief Financial Officer shall attend meetings of the Committee, unless otherwise excused from all or part of any such meeting by the Chairman.

4. The Committee shall forthwith report the results of meetings and reviews undertaken and any associated recommendations to the board.

5. The Committee shall meet with the external auditor at least quarterly (including without management present) and at such other times as the external auditor and the audit Committee consider appropriate.

6. The auditor of Whitecap is entitled to receive notice of every meeting of the Committee and be heard thereat.

7. Meetings may be held by way of telephone conference call.

8. A written resolution signed by all Committee members entitled to vote on that resolution at a meeting of the Committee is as valid as one passed at a Committee meeting.

Mandate and Responsibilities of Committee

1. It is the responsibility of the Committee to oversee the work of the external auditors, including resolution of disagreements between management and the external auditors regarding financial reporting.

2. It is the responsibility of the Committee to satisfy itself on behalf of the Board with respect to Whitecap's Internal Control Systems:

   - identifying, monitoring and mitigating business risks; and

   - ensuring compliance with legal, ethical and regulatory requirements.

3. It is a primary responsibility of the Committee to review the annual and interim financial statements of Whitecap and the notes thereto prior to their submission to the board of directors for approval. The process should include but not be limited to:

   - reviewing changes in accounting principles, or in their application, which may have a material impact on the current or future years' financial statements;

   - reviewing significant accruals, reserves or other estimates such as the ceiling test calculation and reserves with respect to environmental matters;

   - reviewing accounting treatment of unusual or non-recurring transactions;

   - ascertaining compliance with covenants under loan agreements;

   - reviewing disclosure requirements for commitments and contingencies;

   - reviewing adjustments raised by the external auditors, whether or not included in the financial statements;

- reviewing unresolved differences between management and the external auditors; and
- obtain explanations of significant variances with comparative reporting periods.

4. The Committee is to review the financial statements, prospectuses, management discussion and analysis ("**MD&A**"), annual information forms ("**AIF**"), annual reports and all public disclosure containing audited or unaudited financial information before release and prior to board approval. The Committee must be satisfied that adequate procedures are in place for the review of Whitecap's disclosure of all other financial information and shall periodically assess the accuracy of those procedures. The Committee shall also review Whitecap's policies and procedures for making and updating disclosures on Whitecap's website and shall periodically assess the adequacy and accuracy of such policies and procedures.

5. With respect to the appointment of external auditors by the board, the Committee shall:

- ensure the auditor's ultimate accountability to the Board and the Committee as representatives of the shareholders and as such representatives, to evaluate the performance of the auditor;
- recommend to the board the appointment of the external auditors;
- recommend to the board the terms of engagement of the external auditor, including the compensation of the auditors and a confirmation that the external auditors shall report directly to the Committee;
- 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;
- review and approve any non-audit services to be provided by the external auditors' firm and consider the impact on the independence of the auditors;
- ensure that the auditor submits on a periodic basis to the Committee, a formal written statement delineating all relationships between the auditor and Whitecap, consistent with Canadian and other applicable auditor independence standards, and to review such statement and to actively engage in a dialogue with the auditor with respect to any undisclosed relationships or services that may impact on the objectivity and independence of the auditor, and to review the statement and dialogue with the board of directors and recommend to the board of directors appropriate action to ensure the independence of the auditor;
- provide a line of communication between the auditors and the Board; and
- meet with the auditors at least once per quarter without management present to allow a candid discussion regarding any concerns the auditors may have and to resolve any disagreements between the auditor and management regarding Whitecap's financial reporting.

6. Review with external auditors (and internal auditor if one is appointed by Whitecap) their assessment of the internal controls of Whitecap, their written reports containing recommendations for improvement, and management's response and follow-up to any identified weaknesses. The Committee shall also review annually with the external auditors their plan for their audit and, upon completion of the audit, their reports upon the financial statements of Whitecap and its subsidiaries.

7. The Committee must pre-approve all non-audit services to be provided to Whitecap or its subsidiaries by the external auditors. The Committee may delegate to one or more members the authority to pre-approve non-audit services, provided that the member report to the Committee at the next scheduled meeting such pre-approval and the member comply with such other procedures as may be established by the Committee from time to time.

8. The Committee shall review risk management policies and procedures of Whitecap (i.e. hedging, litigation and insurance).

9. The Committee shall establish a procedure for:

   - the receipt, retention and treatment of complaints received by Whitecap regarding accounting, internal accounting controls or auditing matters; and

   - the confidential, anonymous submission by employees of Whitecap of concerns regarding questionable accounting or auditing matters.

10. The Committee shall review and approve Whitecap's hiring policies regarding employees and former employees of the present and former external auditors of Whitecap.

11. The Committee shall have the authority to investigate any financial activity of Whitecap. All employees of Whitecap are to cooperate as requested by the Committee.

12. The Committee shall review all related party transactions.

13. The Committee shall review the status of taxation matters of Whitecap and its major subsidiaries.

14. The Committee shall review the short term investment strategies respecting the cash balance of Whitecap.

15. The Committee shall conduct or undertake such other duties as may be required from time to time by any applicable regulatory authorities, including the TSX.

16. The Committee may retain persons having special expertise and/or obtain independent professional advice to assist in filling their responsibilities at the expense of Whitecap without any further approval of the board.

Approved by the Board of Directors on November 1, 2016.