Hemisphere energy corporation

ANNUAL INFORMATION FORM

For the year ended December 31, 2016

April 19, 2017

TABLE OF CONTENTS

APPENDICES

ABBREVIATIONS

Oil and Natural Gas Liquids		Natural Gas	
bbl	barrels	Mcf	thousand cubic feet
bbl/d	barrels per day	Mcf/d	thousand cubic feet per day
bopd	barrels of oil per day	MMcf	million cubic feet
boe	barrels of oil equivalent	MMbtu	million British thermal units
boe/d	boe per day	Bcf	billion cubic feet
Mboe	thousand barrels of oil equivalent	GJ	gigajoule
Mbbl	thousand barrels		
NGL	natural gas liquids		

Other	
M$	thousands of dollars
$/boe	dollar per barrel of oil equivalent
ha	Hectare
3D	three dimensional
API	American Petroleum Institute
^{o}API	an indication of the specific gravity of crude oil measured on the API gravity scale
AECO	the natural gas storage facility located at Suffield, Alberta, connected to TransCanada's Alberta System
m^3	Cubic metres
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

CONVERSIONS

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

To Convert From	To	Multiply By
Mcf	cubic metres	28.174
cubic metres	cubic feet	35.494
bbl	cubic metres	0.159
cubic metres	Bbl	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

BARREL OF OIL EQUIVALENCY

Barrels of oil equivalent ("boe") may be misleading, particularly if used in isolation. A boe conversion ratio of 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 that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency conversion ratio of 6:1, utilizing a conversion on a 6:1 basis is misleading as an indication of value.

CURRENCY

All amounts are expressed in Canadian dollars unless otherwise stated.

FORWARD-LOOKING STATEMENTS

Certain of the statements contained herein including, without limitation, financial and business prospects and financial outlook, reserve and production estimates, drilling plans, activities to be undertaken in various areas, timing of drilling, recompletion and tie-in of wells, tax horizon, timing of development of undeveloped reserves, commodity prices and foreign exchange rates, planned capital expenditures, the timing thereof and the method of funding may be forward-looking statements which reflect management's expectations regarding future plans and intentions, growth, results of operations, performance and business prospects and opportunities. Words such as "may", "will", "should", "could", "anticipate", "believe", "expect", "intend", "plan", "potential", "continue" and similar expressions may be used to identify these forward-looking statements. These statements reflect management's current beliefs and are based on information currently available to management. Forward-looking statements involve significant risk and uncertainties. A number of factors could cause actual results to differ materially from the results discussed in the forward-looking statements including, but not limited to, risks associated with oil and gas exploration, development, exploitation, production, marketing and transportation, loss of markets, changes in environmental or other legislation, reliance on key management personnel, changes in general economic and business conditions, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers, inability to retain drilling rigs and other services, incorrect assessment of the value of acquisitions, failure to realize the anticipated benefits of acquisitions, delays resulting from or inability to obtain required regulatory approvals and ability to access sufficient capital from internal and external sources and the risk factors outlined under "*Risk Factors*" and elsewhere herein. The recovery and reserve estimates of Hemisphere Energy Corporation's ("Hemisphere" or the "Company") reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. As a consequence, actual results may differ materially from those anticipated in the forward-looking statements. In addition, forward-looking statements may include statements attributable to third party industry sources. There can be no assurances that the plans, intentions or expectations upon which such forward-looking statements are based will occur.

Forward-looking statements and information are based on a number of factors and assumptions which have been used to develop such statements and information but which may prove to be incorrect. Although Hemisphere believes that the expectations reflected in such forward-looking statements and information are reasonable, undue reliance should not be placed on forward-looking statements because Hemisphere can give no assurance that such expectations will prove to be correct. In addition to other factors and assumptions which may be identified in this document, assumptions have been made regarding, among other things: the impact of increasing competition; the general stability of the economic and political environment in which Hemisphere operates; the timely receipt of any required regulatory approvals; the ability of Hemisphere to obtain qualified staff, equipment and services in a timely and cost efficient manner; drilling results, the ability of the operator of the projects which Hemisphere has an interest in to operate the project in a safe, efficient and effective manner; the ability of Hemisphere to obtain financing on acceptable terms; well production rates and decline rates; the ability to replace and expand the oil and natural gas reserves through acquisition, development of exploration; the timing and costs of pipeline, storage and facility construction and expansion and the ability of Hemisphere to secure adequate product transportation; future oil and natural gas prices; currency, exchange and interest rates; the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which Hemisphere operates; and the ability of Hemisphere to successfully market its oil and natural gas products.

Readers are cautioned that the foregoing list of factors is not exhaustive. Additional information on these and other factors that could affect Hemisphere's operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed through the System for Electronic Document Analysis and Retrieval ("SEDAR") at www.sedar.com and Hemisphere's website at www.hemisphereenergy.ca.

Although the forward-looking statements and information contained herein are based upon what management believes to be reasonable assumptions, management cannot give assurance that actual results will be consistent with such forward-looking statements and information. Investors should not place undue reliance on forward-looking statements and information. These forward-looking statements and information are made as of the date of this annual information form ("AIF") and Hemisphere assumes no obligation to update or review them to reflect new events or circumstances except as required by applicable securities laws.

Forward-looking statements and information contained herein concerning the oil and gas industry and Hemisphere's general expectations concerning this industry is based on estimates prepared by management using data from publicly available industry sources as well as from reserve reports, market research and industry analysis and on assumptions based on data and knowledge of this industry, which Hemisphere believes to be reasonable. However, this data is inherently imprecise. While Hemisphere is not aware of any misstatements regarding any industry data presented herein, the industry involves risks and uncertainties and is subject to change based on various factors.

NON-GAAP MEASURES

Within this AIF, references are made to terms commonly used in the oil and natural industry which do not have standardized measures prescribed by generally accepted accounting principles in Canada. The Company uses operating netback as a key performance indicator and is used in operational and capital allocation decisions. It is determined by deducting royalties and operating costs, net of transportation costs, from petroleum and natural gas revenue. Readers are cautioned; however, that operating netback does not have a standardized measure prescribed by generally accepted accounting principles in Canada and this measure should not be construed as an alternative to net earnings or cash flow from operating activities determined in accordance with generally accepted accounting principles in Canada as an indication of our performance.

DESCRIPTION OF THE COMPANY

General

Hemisphere Energy Corporation was incorporated under the laws of the Province of British Columbia on March 6, 1978 and is governed by the *Business Corporations Act* (British Columbia) (the "BCBCA"). The Company does not have any subsidiaries. Hemisphere's head office is located at Suite 2000, 1055 West Hastings Street, Vancouver, British Columbia V6E 2E9 and its registered office is located at Suite 2000, 1055 West Hastings Street, Vancouver, British Columbia V6E 2E9.

Hemisphere produces oil and natural gas from its Jenner and Atlee Buffalo properties in southeast Alberta and is focused on developing conventional oil assets with low risk drilling opportunities. The Company trades on the TSX Venture Exchange ("TSX-V") as a Tier 1 issuer under the symbol "HME".

Three Year History of the Company

Fiscal year ended December 31, 2014

On March 13, 2014, the Company announced that its board of directors ("Board of Directors") approved the adoption of an Advance Notice Policy (the "Policy"). The purpose of the Policy is to: (i) facilitate an orderly and efficient annual general or, where the need arises, special meeting, process, (ii) ensure that all shareholders receive adequate notice of the director nominations and sufficient information regarding all director nominees, and (iii) allow shareholders to register an informed vote after having been afforded reasonable time for appropriate deliberation. The Policy was ratified by the shareholders of the Company at the Company's annual general and special meeting held June 6, 2014.

On May 14, 2014, Hemisphere closed a bought deal equity financing (the "2014 Financing") with a syndicate of underwriters for aggregate gross proceeds of $10.0 million to accelerate its capital program focused on Atlee Buffalo and Jenner. The 2014 Financing resulted in the issuance of 13,333,500 common shares.

On September 9, 2014, the Company announced the promotion of Mr. Ian Duncan from Vice President of Engineering to Chief Operating Officer and the appointment of Ms. Ashley Ramsden-Wood to Vice President of Engineering.

On October 7, 2014, the Company appointed Mr. Richard Wyman to the Board of Directors.

Effective November 28, 2014, the Company successfully increased the borrowing base under its credit facility (the "Credit Facility") to $15.0 million as a result of the drilling activities and production growth from the Company's 2014 capital program.

During the year, Hemisphere successfully drilled 10 horizontal oil wells in Atlee Buffalo, two horizontal oil wells in Jenner, and one vertical test well in Jenner. The Company expanded its landholdings through Crown land sales acquiring 2,560 hectares in southeast Alberta. Hemisphere installed a solution gas compressor at the Company's main production facility in Jenner to increase volume through-put. The Company also acquired 3D seismic in each of the Atlee Buffalo and Jenner areas.

Fiscal year ended December 31, 2015

During the second quarter of 2015, the Company completed a strategic tuck-in acquisition for the remaining 15% working interest in 1.75 sections of land in Atlee Buffalo to bring the Company's total working interest to 100%.

In July 2015, the Company renewed its $15.0 million Credit Facility following the annual review with its lender.

Effective September 15, 2015, the Company requested Smythe Ratcliffe LLP resign as its auditor and, on the recommendation of the Company's Audit Committee, the Board of Directors appointed KPMG LLP as the Company's auditor.

During the year, the Company expanded its landholdings through Crown land sales acquiring 4.5 sections in southeast Alberta. The Company also initiated three waterflood pilot projects in Atlee Buffalo and completed the construction of a new pipeline in Jenner to increase water disposal capacity at an existing disposal well.

Fiscal year ended December 31, 2016

In April 2016 Hemisphere started injection at a fourth waterflood pilot project in Atlee Buffalo.

In May 2016, the borrowing base under the Credit Facility was amended to $12.5MM following the annual review with its lender.

On June 29, 2016, the Company closed the first tranche of a non-brokered private placement offering. The Company issued 2,743,000 common shares at a price of $0.21 per share, which were issued on a Canadian Development Expense flow-through basis pursuant to the provisions of the *Income Tax Act* (Canada), and 2,449,500 common shares of Hemisphere at a price of $0.19 per share, for gross proceeds to the Company of $1,041,435.

On July 12, 2016, the Company closed the second and final tranche of its non-brokered private placement offering. The Company issued 527,000 flow-through shares at a price of $0.21 cents per share, which were issued on a Canadian development expense flow-through basis pursuant to the provisions of the Income Tax Act (Canada), and 4,047,104 common shares of Hemisphere at a price of $0.19 per share, for gross proceeds to the company of $879,620.

In the third quarter, Hemisphere drilled and placed on production its first producing well from the Atlee Buffalo Upper Mannville G pool. It also completed construction of a water handling and reinjection facility for production from the Atlee Buffalo Upper Mannville F pool.

In the fourth quarter, Hemisphere took over minor working interests in two of its Jenner wells, bringing the working interest of all its wells to 100%.

Significant Acquisitions

The Company did not make any significant acquisitions during 2016.

Competition

The oil and gas industry is competitive in all its phases. The Company competes with numerous other participants in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas. The Company's competitors include resource companies that have greater financial resources, staff and facilities than those of the Company. Competitive factors in the distribution and marketing of oil and natural gas include price and methods and reliability of delivery. The Company believes that its competitive position is equivalent to that of other oil and gas issuers of similar size and at a similar stage of development.

Seasonal Factors

The exploration for and development of oil and natural gas reserves is dependent on access to areas where production is to be conducted. Seasonal weather variations, including freeze-up and break-up, affect access to the Company's oil and gas properties in certain circumstances.

Commodity Prices

The Company's operational results and financial condition will be dependent on the prices received for oil and natural gas production. Oil and natural gas prices have fluctuated widely during recent years and are determined by supply and demand factors, including, but not limited to, 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 the Company's financial condition and such effect could be material. See *"Risk Factors"*.

Environmental Regulation

The oil and gas industry is subject to environmental regulations pursuant to applicable legislation. Such legislation provides for restrictions and prohibitions on release or emission of various substances produced in association with certain oil and gas industry operations, and requires that well and facility sites be abandoned and reclaimed to the satisfaction of environmental authorities. No assurance can be given that the application of environmental laws to the business and operations of the Company will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise adversely affect the Company's financial condition, results of operations or prospects. See *"Risk Factors"*.

Human Resources

As at December 31, 2016, Hemisphere had seven full-time head office employees and one full-time field employee. Additionally, the Company had six part-time consultants and two full-time field contractors.

Specialized Skill and Knowledge

The Company relies on specialized skills and knowledge to gather, interpret and process geophysical data, operate production facilities and numerous additional activities required to produce oil and natural gas. The Company has employed a strategy of contracting consultants and other service providers to supplement the skills and knowledge of its permanent staff in order to provide the specialized skills and knowledge to undertake its oil and natural gas operation effectively.

Risk Factors

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

Exploration, Development and Production Risks

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of the Company depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, the Company's existing reserves, and the production from them, will decline over time as the Company produces from such reserves. A future increase in the Company's reserves will depend on both the ability of the Company to explore and develop its existing properties and its ability to select and acquire suitable producing properties or prospects. There is no assurance that the Company will be able continue to find satisfactory properties to acquire or participate in. Moreover, management of the Company may determine that current markets, terms of acquisition, participation or pricing conditions make potential acquisitions or participation uneconomic. There is also no assurance that the Company 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 other geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, it is not possible to eliminate production delays and declines from normal field operating conditions, which can negatively affect revenue and cash flow levels to varying degrees.

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

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

As is standard industry practice, the Company is not fully insured against all risks, nor are all risks insurable. Although the Company maintains liability insurance in an amount that it considers consistent with industry practice, liabilities associated with certain risks could exceed policy limits or not be covered. In either event the Company 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 ("**OPEC**"), slowing growth in emerging economies, market volatility and disruptions in Asia, sovereign debt levels and political upheavals in various countries have caused significant weakness and volatility in commodity prices. These events and conditions have caused a significant decrease in the valuation of oil and gas companies and a decrease in confidence in the oil and gas industry. These difficulties have been exacerbated in Canada by the recent changes in government at a federal level and, in the case of Alberta, at the provincial level, and the resultant uncertainty surrounding regulatory, tax, royalty changes and environmental regulations that have been announced or may be implemented by the new governments. In addition, the inability to get the necessary approvals to build pipelines and other facilities to provide better access to markets for the oil and gas industry in Western Canada has led to additional downward price pressure on oil and gas produced in Western Canada and uncertainty and reduced confidence in the oil and gas industry in Western Canada. Lower commodity prices may also affect the volume and value of the Company's reserves, rendering certain reserves uneconomic. In addition, lower commodity prices have restricted, and are anticipated to continue to restrict, the Company's cash flow resulting in a reduced capital expenditure budget. Consequently, the Company may not be able to replace its production with additional reserves and both the Company's production and reserves could be reduced on a year over year basis. Any decrease in value of the Company's reserves may reduce the borrowing base under its credit facilities, which, depending on the level of the Company's indebtedness, could result in the Company having to repay a portion of its indebtedness. Given the current market conditions and the lack of confidence in the Canadian oil and gas industry, the Company may have difficulty raising additional funds or if it is able to do so, it may be on unfavourable and highly dilutive terms. If these conditions persist, the Company's cash flow may not be sufficient to continue to fund its operations and to satisfy its obligations when due and the Company's ability to continue as a going concern and discharge its obligations will require additional equity or debt financing and/or proceeds or reduction in liabilities from asset sales. There can be no assurance that such equity or debt financing will be available on terms that are satisfactory to the Company or at all. Similarly, there can be no assurance that the Company will be able to realize any or sufficient proceeds or reduction in liabilities from asset sales to discharge its obligations and continue as a going concern.

Prices, Markets and Marketing

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

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

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

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

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

Market Price of Common Shares

The trading price of securities of oil and natural gas issuers is subject to substantial volatility often based on factors related and unrelated to the financial performance or prospects of the issuers involved. Factors unrelated to the Company's 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 the common shares of the Company could be subject to significant fluctuations in response to variations in the Company's operating results, financial condition, liquidity and other internal factors. Accordingly, the price at which the common shares of the Company will trade cannot be accurately predicted.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

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

Political Uncertainty

In the last several years, the United States and certain European countries have experienced significant political events that have cast uncertainty on global financial and economic markets. During the recent presidential campaign a number of election promises were made and the new American administration has begun taking steps to implement certain of these promises. Included in the actions that the administration has discussed are the renegotiation of the terms of the North American Free Trade Agreement, withdrawal of the United States from the Trans-Pacific Partnership, imposition of a tax on the importation of goods into the United States, reduction of regulation and taxation in the United States, and introduction of laws to reduce immigration and restrict access into the United States for citizens of certain countries. It is presently unclear exactly what actions the new administration in the United States will implement, and if implemented, how these actions may impact Canada and in particular the oil and gas industry. Any actions taken by the new United States administration may have a negative impact on the Canadian economy and on the businesses, financial conditions, results of operations and the valuation of Canadian oil and gas companies, including the Company.

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

Operational Dependence

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

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

Project Risks

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

- the availability of processing capacity;
- the availability and proximity of pipeline capacity;
- the availability of storage capacity;

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

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

Gathering and Processing Facilities, Pipeline Systems and Rail

The Company delivers its products through gathering and processing facilities, pipeline systems and, in certain circumstances, by rail. The amount of oil and natural gas that the Company 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 the Company's inability to realize the full economic potential of its production or in a reduction of the price offered for the Company's 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 the Company's production, operations and financial results. As a result, producers are increasingly turning to rail as an alternative means of transportation. In recent years, the volume of crude oil shipped by rail in North America has increased dramatically. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays or uncertainty in constructing new infrastructure systems and facilities could harm the Company's business and, in turn, the Company's financial condition, 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 the Company's production may, from time to time, be processed through facilities owned by third parties and over which the Company does not have control. From time to time, these facilities may discontinue or decrease operations either as a result of normal servicing requirements or as a result of unexpected events. A discontinuation or decrease of operations could have a materially adverse effect on the Company's ability to process its production and deliver the same for sale.

Competition

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

Cost of New Technologies

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

Alternatives to and Changing Demand for Petroleum Products

Full conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas and technological advances in fuel economy and energy generation devices could reduce the demand for oil, natural gas and liquid hydrocarbons. The Company cannot predict the impact of changing demand for oil and natural gas products, and any major changes may have a material adverse effect on the Company's business, financial condition, results of operations and cash flows.

Regulatory

Various levels of governments impose extensive controls and regulations on oil and natural gas operations (including exploration, development, production, pricing, marketing and transportation). Governments may regulate or intervene with respect to exploration and production activities, prices, taxes, royalties and the exportation of oil and natural gas. Amendments to these controls and regulations may occur from time to time in response to economic or political conditions. See "*Industry Conditions*". The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for crude oil and natural gas and increase the Company's costs, either of which may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. In order to conduct oil and natural gas operations, the Company will require regulatory permits, licenses, registrations, approvals and authorizations from various governmental authorities at the provincial and federal level. There can be no assurance that the Company will be able to obtain all of the permits, licenses, registrations, approvals and authorizations that may be required to conduct operations that it may wish to undertake. In addition, certain federal legislation such as the Competition Act and the Investment Canada Act could negatively affect the Company's business, financial condition and the market value of its common shares or its assets, particularly when undertaking, or attempting to undertake, acquisition or disposition activity.

Royalty Regimes

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

Waterflood Operations

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

Environmental

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

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

Liability Management

Alberta and British Columbia have developed liability management programs designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licensee or permit holder is unable to satisfy its obligation. These programs generally involve an assessment of the ratio of a licensee's deemed assets to deemed liabilities. If a licensee's deemed liabilities exceed its deemed assets, a security deposit is required. Changes to the required ratio of the Company's deemed assets to deemed liabilities or other changes to the requirements of liability management programs may result in significant increases to the Company's compliance requirement. In addition, the liability management system may prevent or interfere with the Company's ability to acquire or dispose of assets as both the vendor and the purchaser of oil and gas assets must be in compliance with the liability management programs (both before and after the transfer of the assets) for the applicable regulatory agency to allow for the transfer of such assets. This is of particular concern to junior oil and gas companies that may be disproportionately affected by price instability. The recent Alberta Court of Queen's Bench decision, *Redwater Energy Company (Re)* 2016 ABQB 278, found an operational conflict between the Bankruptcy and Insolvency Act and the AER's abandonment and reclamation powers when the licensee is insolvent. The AER appealed this decision and issued interim rules to administer the liability management program and until the Alberta Government can develop new regulatory measures to adequately address environmental liabilities. The decision from this appeal has not been released. There remains a great deal of uncertainty as to what new regulatory measures will be developed or what the impact of the court decision will have on other provinces. See "*Industry Conditions - Liability Management Rating Programs*".

Climate Change

The Company's exploration and production facilities and other operations and activities emit greenhouse gases which may require the Company to comply with greenhouse gas ("**GHG**") emissions legislation at the provincial or federal level. Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place. As a signatory to the *United Nations Framework Convention on Climate Change* (the "**UNFCCC**") and a participant to the Copenhagen Agreement (a non-binding agreement created by the UNFCCC), the Government of Canada announced on January 29, 2010 that it would seek a 17% reduction in GHG emissions from 2005 levels by 2020; however, these GHG emission reduction targets were not binding. As a result of the UNFCCC adopting the Paris Agreement on December 12, 2015, which Canada ratified on October 3, 2016, the Government of Canada implemented new GHG emission reduction targets of a 30% reduction from 2005 levels by 2030. In addition, the Government of Canada announced it would implement a Canada wide price on carbon to further reduce its GHG emissions. In addition, on January 1, 2017 the *Climate Leadership Act* ("**CLA**") come into effect in the Province of Alberta introducing a carbon tax on almost all sources of GHG emissions at a rate of $20 per tonne, increasing to $30 per tonne in January 2018. The direct or indirect costs of compliance with these regulations may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. Some of the Company's significant facilities may ultimately be subject to future regional, provincial and/or federal climate change regulations to manage GHG emissions. In addition, concerns about climate change have resulted in a number of environmental activists and members of the public opposing the continued exploitation and development of fossil fuels. Given the evolving nature of the debate related to climate change and the control of GHG and resulting requirements, it is not possible to predict the impact on the Company and its operations and financial condition. See "*Industry Conditions - Climate Change Regulation*".

Variations in Foreign Exchange Rates and Interest Rates

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

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

An increase in interest rates could result in a significant increase in the amount the Company pays to service debt, resulting in a reduced amount available to fund its exploration and development activities, and if applicable, the cash available for dividends and could negatively impact the market price of the common shares of the Company.

Substantial Capital Requirements

The Company anticipates 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, the Company's ability to do so is dependent on, among other factors:

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

Further, if the Company's revenues or reserves decline, it 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 the Company. The Company may be required to seek additional equity financing on terms that are highly dilutive to existing shareholders. The inability of the Company to access sufficient capital for its operations could have a material adverse effect on the Company's business financial condition, results of operations and prospects.

Additional Funding Requirements

The Company's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times and from time to time, the Company may require additional financing in order to carry out its oil and natural gas acquisition, exploration and development activities. Failure to obtain financing on a timely basis could cause the Company to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. Due to the conditions in the oil and gas industry and/or global economic and political volatility, the Company 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, the Company 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 the Company to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If the Company's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect the Company's ability to expend the necessary capital to replace its reserves or to maintain its production. To the extent that external sources of capital become limited, unavailable or available on onerous terms, the Company's ability to make capital investments and maintain existing assets may be impaired, and its assets, liabilities, business, financial condition and results of operations may be affected materially and adversely as a result. In addition, the future development of the Company's petroleum properties may require additional financing and there are no assurances that such financing will be available or, if available, will be available upon acceptable terms. Alternatively, any available financing may be highly dilutive to existing shareholders. Failure to obtain any financing necessary for the Company's capital expenditure plans may result in a delay in development or production on the Company's properties.

Credit Facility Arrangements

The Credit Facility and the amount authorized thereunder is dependent on the borrowing base determined by its lenders. The Company is required to comply with covenants under its 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 the Company does not comply with these covenants, the Company's access to capital could be restricted or repayment could be required. Events beyond the Company's control may contribute to the failure of the Company to comply with such covenants. A failure to comply with covenants could result in default under the Credit Facility, which could result in the Company being required to repay amounts owing thereunder. The acceleration of the Company's indebtedness under one agreement may permit acceleration of indebtedness under other agreements that contain cross default or cross-acceleration provisions. In addition, the Credit Facility may impose operating and financial restrictions on the Company that could include restrictions on, the payment of dividends, repurchase or making of other distributions with respect to the Company's 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. As the Credit Facility is a demand facility, the lenders may demand repayment by the Company at any time.

The Company's lenders use the Company's reserves, commodity prices, applicable discount rate and other factors, to periodically determine the Company's borrowing base. Commodity prices continue to be depressed and have fallen dramatically since 2014. There remains a substantial amount of uncertainty as to how much commodity prices will recover. Depressed commodity prices could reduce the Company's borrowing base, reducing the funds available to the Company under the credit facility. This could result in the requirement to repay a portion, or all, of the Company's indebtedness.

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

Issuance of Debt

From time to time, the Company may enter into transactions to acquire assets or shares of other organizations. These transactions may be financed in whole or in part with debt, which may increase the Company's debt levels above industry standards for oil and natural gas companies of similar size. Depending on future exploration and development plans, the Company may require additional debt financing that may not be available or, if available, may not be available on favourable terms. Neither the Company's articles nor its by-laws limit the amount of indebtedness that the Company may incur. The level of the Company's indebtedness from time to time could impair the Company's ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise.

Hedging

From time to time, the Company may enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline. However, to the extent that the Company engages in price risk management activities to protect itself from commodity price declines, it may also be prevented from realizing the full benefits of price increases above the levels of the derivative instruments used to manage price risk. In addition, the Company's hedging arrangements may expose it 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 the Company may enter into agreements to fix the exchange rate of Canadian to United States dollars or other currencies in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to other currencies. However, if the Canadian dollar declines in value compared to such fixed currencies, the Company 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 the Company and may delay exploration and development activities.

Diluent Supply

Heavy oil and bitumen are characterized by high specific gravity or weight and high viscosity or resistance to flow. Diluent is required to facilitate the transportation of heavy oil and bitumen. A shortfall in the supply of diluent may cause its price to increase thereby increasing the cost to transport heavy oil and bitumen to market and correspondingly increasing the Company's overall operating cost, decreasing its net revenues and negatively impacting the overall profitability of its heavy oil and bitumen projects.

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

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 document are estimates only. Generally, estimates of economically recoverable oil and natural gas reserves and the future net cash flows from such estimated reserves are based upon a number of variable factors and assumptions, such as:

- historical production from the properties;
- production rates;
- ultimate reserve recovery;
- timing and amount of capital expenditures;
- marketability of oil and natural gas;
- royalty rates; and

- the assumed effects of regulation by governmental agencies and future operating costs (all of which may vary materially from actual results).

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

The estimation of proved reserves that may be developed and produced in the future is often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Recovery factors and drainage areas 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, the Company's 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 the Company's 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 the Company intends to undertake in future years. The reserves and estimated cash flows to be derived therefrom and contained in the reserve evaluation will be reduced to the extent that such activities do not achieve the level of success assumed in the reserve evaluation. The reserve evaluation is effective as of a specific effective date and, except as may be specifically stated, has not been updated and therefore does not reflect changes in the Company's reserves since that date.

Insurance

The Company's involvement in the exploration for and development of oil and natural gas properties may result in the Company becoming subject to liability for pollution, blow outs, leaks of sour natural gas, property damage, personal injury or other hazards. Although the Company maintains 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, the Company may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of any uninsured liabilities would reduce the funds available to the Company. The occurrence of a significant event that the Company is not fully insured against, or the insolvency of the insurer of such event, may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Geopolitical Risks

Political events throughout the world that cause disruptions in the supply of oil continuously affect the marketability and price of oil and natural gas acquired or discovered by the Company. 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 the Company's net production revenue.

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

Dilution

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

Management of Growth

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

Expiration of Licences and Leases

The Company's properties are held in the form of licences and leases and working interests in licences and leases. If the Company 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 the Company's licences or leases or the working interests relating to a licence or lease may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Litigation

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

Aboriginal Claims

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

Breach of Confidentiality

While discussing potential business relationships or other transactions with third parties, the Company may disclose confidential information relating to the business, operations or affairs of the Company. Although confidentiality agreements are generally signed by third parties prior to the disclosure of any confidential information, a breach could put the Company at competitive risk and may cause significant damage to its business.

The harm to the Company's business from a breach of confidentiality cannot presently be quantified, but may be material and may not be compensable in damages. There is no assurance that, in the event of a breach of confidentiality, the Company will be able to obtain equitable remedies, such as injunctive relief, from a court of competent jurisdiction in a timely manner, if at all, in order to prevent or mitigate any damage to its business that such a breach of confidentiality may cause.

Income Taxes

The Company files all required income tax returns and believes that it is in full compliance with the provisions of the Income Tax Act and all other applicable provincial tax legislation. However, such returns are subject to reassessment by the applicable taxation authority. In the event of a successful reassessment of the Company, 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 the Company. Furthermore, tax authorities having jurisdiction over the Company may disagree with how the Company calculates its income for tax purposes or could change administrative practices to the Company's 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 the Company's ability to access its 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 the goods and services of the Company.

Third Party Credit Risk

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

Conflicts of Interest

Certain directors or officers of the Company 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 BCBCA which require a director of officer of a Company who is a party to, or is a director or an officer of, or has a material interest in any person who is a party to, a material contract or proposed material contract with the Company 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 BCBCA. See "Directors and Officers – Conflicts of Interest".

Reliance on Key Personnel

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

Dividends

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

Information Technology Systems and Cyber-Security

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

Further, the Company is subject to a variety of information technology and system risks as a part of its normal course operations, including potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach, and destruction or interruption of the Company's information technology systems by third parties or insiders. Unauthorized access to these systems by employees or third parties could lead to corruption or exposure of confidential, fiduciary or proprietary information, interruption to communications or operations or disruption to our business activities or our competitive position. Further, disruption of critical information technology services, or breaches of information security, could have a negative effect on our performance and earnings, as well as on our reputation. The Company applies technical and process controls in line with industry-accepted standards to protect our information assets and systems; however, these controls may not adequately prevent cyber-security breaches. The significance of any such event is difficult to quantify, but may in certain circumstances be material and could have a material adverse effect on the Company's business, financial condition and results of operations.

Expansion into New Activities

The operations and expertise of the Company's management are currently focused primarily on oil and gas production, exploration and development in the Western Canada Sedimentary Basin. In the future the Company 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 the Company's exposure to one or more existing risk factors, which may in turn result in the Company's 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 the Company's forward-looking information. By its nature, forward-looking information involves numerous assumptions, known and unknown risk and uncertainties, of both a general and specific nature, that could cause actual results to differ materially from those suggested by the forward-looking information or contribute to the possibility that predictions, forecasts or projections will prove to be materially inaccurate.

Additional information on the risks, assumption and uncertainties are found under the heading "Forward-Looking Statements" of this AIF.

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 and British Columbia all of which should be carefully considered by investors in the oil and gas industry. All current legislation is a matter of public record and the Company is unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and 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 also influence prices. The specific price depends in part on oil quality, prices of competing fuels, distance to market, availability of transportation, value of refined products, the supply/demand balance and contractual terms of sale. Oil exporters are also entitled to enter into export contracts with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude oil, provided that an order approving such export has been obtained from the National Energy Board of Canada (the "NEB"). Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export license from the NEB. The NEB underwent a consultation process to update the regulations governing the issuance of export licences. The updating process was necessary to meet the criteria set out in the federal *Jobs, Growth and Long-term Prosperity Act (Canada)* (the "**Prosperity Act**") which received Royal Assent on June 29, 2012. The *Regulations Amending the National Energy Board Act Part VI (Oil and Gas) Regulations* came into effect on July 31, 2015 and provides the requirements for obtaining long-term licences.

Natural Gas

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

The North American Free Trade Agreement

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

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

Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations that govern royalties, production rates and other matters. The royalty regime in a given province is a significant factor in the profitability of oil sands projects, crude oil, 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 ("**AER**").

Oil sands projects are also subject to Alberta's royalty regime. The MRF does not change the oil sands royalty framework, however, the Government of Alberta plans to increase transparency in the method and figures by which the royalties are calculated. Prior to payout of an oil sands project, the royalty is payable on gross revenues of an oil sands project. Gross revenue royalty rates range between 1% and 9% depending on the market price of oil, determined using the average monthly price, expressed in Canadian dollars, for WTI crude oil at Cushing, Oklahoma. Rates are 1% when the market price of oil is less than or equal to $55 per barrel and increase for every dollar of market price of oil increase to a maximum of 9% when oil is priced at $120 or higher. After payout, the royalty payable is the greater of the gross revenue royalty based on the gross revenue royalty rate of between 1% and 9% and the net revenue royalty based on the net revenue royalty rate. Net revenue royalty rates start at 25% and increase for every dollar of market price of oil increase above $55 up to 40% when oil is priced at $120 or higher.

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

Royalties, for wells drilled prior to January 1, 2017 are paid pursuant to the Alberta Royalty Framework until January 1, 2027. Royalty rates for conventional oil are set by a single sliding scale formula, which is applied monthly and incorporates separate variables to account for production rates and market prices. The maximum royalty payable under the royalty regime is 40%. Royalty rates for natural gas under the royalty regime depends on the price of each of the components of the gas stream, the productivity of the well, its acid gas factor and the depth of the producing zone. These factors are employed on a sliding scale formula to determine the natural gas royalty rate per well with the maximum royalty payable under the royalty regime set at 36% and a minimum royalty rate of 5%.

Producers of oil and natural gas from freehold lands in Alberta are required to pay freehold mineral tax. The freehold mineral tax is a tax levied by the Government of Alberta on the value of oil and natural gas production from lands where the Crown does not hold the rights to mines and minerals and is derived from the Freehold Mineral Rights Tax Act (Alberta). The freehold mineral tax is levied on an annual basis on calendar year production using a tax formula that takes into consideration, among other things, the amount of production, the hours of production, the value of each unit of production, the tax rate and the percentages that the owners hold in the title. The basic formula for the assessment of freehold mineral tax is: revenue less allocable costs equals net revenue divided by wellhead production equals the value based upon unit of production. If payors do not wish to file individual unit values, a default price is supplied by the Crown. On average, the tax levied is 4% of revenues reported from freehold mineral title properties.

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

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

- Coalbed methane wells will receive a maximum royalty rate of 5% for 36 producing months up to 750 MMcf of production, retroactive to wells that began producing on or after May 1, 2010;

- Shale gas wells will receive a maximum royalty rate of 5% for 36 producing months with no limitation on production volume, retroactive to wells that began producing on or after May 1, 2010;

- Horizontal gas wells will receive a maximum royalty rate of 5% for 18 producing months up to 500 MMcf of production, retroactive to wells that commenced drilling on or after May 1, 2010; and

- Horizontal oil wells and horizontal non-project oil sands wells will receive a maximum royalty rate of 5% with volume and production month limits set according to the depth of the well (including the horizontal distance), retroactive to wells that commenced drilling on or after May 1, 2010.

British Columbia

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

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

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

- *Deep Well Royalty Credit Program* providing a royalty credit for natural gas wells defined in terms of a dollar amount applied against royalties, is well specific and applies to drilling and completion costs for vertical wells with a true vertical depth greater than 2,500 metres and horizontal wells with a true vertical depth greater than 1,900 metres (or 2,300 metres if spud before September 1, 2009) and if certain other criteria are met, is intended to reflect the higher drilling and completion costs. Effective April 1, 2014, there are two tiers to the Deep Well Royalty Credit Program, "tier one" and "tier two". The pre-existing Deep Well Royalty Credit Program, as described above, will comprise tier two of the program. Tier one of the Deep Well Royalty Credit Program applies to shallower horizontal wells with a true vertical depth less than or equal to 1,900 metres if spud after March 31, 2014. Currently all wells that qualify for the tier one royalty credits are subject to a minimum royalty of 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 25,000 m^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 17 m^3 per metre of depth for exploratory wildcat wells and less than 11 m^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 60,000 m^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.

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 and British Columbia have implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a lease or licence. The Government of British Columbia expanded its policy of deep rights reversion for leases issued after March 29, 2007 to provide for the reversion of both shallow and deep formations that cannot be shown to be capable of production at the end of the primary term.

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

Production and Operation Regulations

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

Environmental Regulation

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

Federal

Canadian environmental regulation is the responsibility of the federal government and provincial governments. Where there is a direct conflict between federal and provincial environmental legislation in relation to the same matter, the federal law will prevail, however, such conflicts are uncommon. The federal government has primary jurisdiction over federal works, undertakings and federally regulated industries such as railways, aviation and interprovincial transport. The *Canadian Environmental Protection Act, 1999* and the *Canadian Environmental Assessment Act, 2012* provide the foundation for the federal government to protect the environment and cooperate with provinces to do the same.

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

On June 20, 2016, the Federal Government launched a review of current environmental and regulatory processes with a focus on rebuilding trust in the environmental assessment processes, modernizing the NEB, and introducing modernized safeguards to both the *Fisheries Act* and the *Navigation Protection Act*. An Expert Panel has been convened and is expected to complete its work by March 31, 2017. At such time, the Minister of Environment and Climate Change will consider the recommendations in the Panel's report and identify next steps to improve federal environmental processes, which is expected to take place during the summer/fall of 2017. Until this process is complete, the Federal Government's interim principles released January 27, 2016 will continue to guide decision-making authorities for projects currently undergoing environmental assessment. The Federal Government has not provided any indication on what changes—if any—will be implemented or when, but increased delays and uncertainty surrounding the environmental assessment process should be expected for large projects.

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

Alberta

The AER is the single regulator responsible for all energy development in Alberta. The AER ensures the safe, efficient, orderly and environmentally responsible development of hydrocarbon resources including allocating and conserving water resources, managing public lands, and protecting the environment. The AER's responsibilities exclude the functions of the Alberta Utilities Commission and the Surface Rights Board, as well as Alberta Energy's responsibility for mineral tenure. The objective behind a single regulator is an enhanced regulatory regime that is efficient, attractive to business and investors, and effective in supporting public safety, environmental management and resource conservation while respecting the rights of landowners.

The Government of Alberta relies on regional planning to accomplish its responsible resource development goals. The following frameworks, plans and policies form the basis of Alberta's Integrated Resource Management System ("**IRMS**"). The IRMS method to natural resource management provides for engagement and consultation with stakeholders and the public and examines the cumulative impacts of development on the environment and communities, by incorporating the management of all resources, including energy, minerals, land, air, water and biodiversity. While the AER is the primary regulator for energy development, several other governmental departments and agencies may be involved in land use issues, including Alberta Environment and Parks, Alberta Energy, the Policy Management Office, the Aboriginal Consultation Office and the Land Use Secretariat.

In December 2008, the Government of Alberta released a new land use policy for surface land in Alberta, the Alberta Land Use Framework (the "**ALUF**"). The ALUF sets out an approach to manage public and private land use and natural resource development in a manner that is consistent with the long-term economic, environmental and social goals of the province. It calls for the development of seven region-specific land use plans in order to manage the combined impacts of existing and future land use within a specific region and the incorporation of a cumulative effects management approach into such plans.

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

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

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

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

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

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

British Columbia

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

Liability Management Rating Programs

Alberta

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

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

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

1. The AER will consider and process all applications for licence eligibility under *Directive 067: Applying for Approval to Hold EUB Licences* as non-routine and may exercise its discretion to refuse an application or impose terms and conditions on a licencee eligibility approval if appropriate in the circumstances.

2. For holders of existing but previously unused licence eligibility approvals, prior to approval of any application (including licence transfer applications), the AER may require evidence that there have been no material changes since approving the licence eligibility. This may include evidence that the holder continues to maintain adequate insurance and that the directors, officers, and/or shareholders are substantially the same as when licence eligibility was originally granted.

3. As a condition of transferring existing AER licences, approvals, and permits, the AER will require all transferees to demonstrate that they have a liability management rating ("**LMR**"), being the ratio of a licensee's assets to liabilities, of 2.0 or higher immediately following the transfer.

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

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

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

The AER implemented the Inactive Well Compliance Program (the "**IWCP**") to address the growing inventory of inactive wells in Alberta and to increase the AER's surveillance and compliance efforts under *Directive 013: Suspension Requirements for Wells* ("***Directive 013***"). The IWCP applies to all inactive wells that are noncompliant with *Directive 013* as of April 1, 2015. The objective is to bring all inactive noncompliant wells under the IWCP into compliance with the requirements of *Directive 013* within 5 years. As of April 1, 2015, each licensee is required to bring 20% of its inactive wells into compliance every year, either by reactivating or by suspending the wells in accordance with Directive 013 or by abandoning them in accordance with *Directive 020: Well Abandonment*. The list of current wells subject to the IWCP is available on the AER's Digital Data Submission system. The AER has announced that from April 1, 2015 to April 1, 2016, the number of noncompliant wells subject to the IWCP fell from 25,792 to 17,470, with 76% of licensees operating in the province having met their annual quota.

British Columbia

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

Climate Change Regulation

Federal

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

On April 26, 2007, the Government of Canada released "Turning the Corner: An Action Plan to Reduce Greenhouse Gases and Air Pollution" (the "**Action Plan**") which set forth a plan for regulations to address both GHGs and air pollution. An update to the Action Plan, "Turning the Corner: Regulatory Framework for Industrial Greenhouse

Gas Emissions" was released on March 10, 2008 (the "**Updated Action Plan**"). The Updated Action Plan outlines emissions intensity-based targets, for application to regulated sectors on a facility-specific basis, sector-wide basis or company-by-company basis. Although the intention was for draft regulations aimed at implementing the Updated Action Plan to become binding on January 1, 2010, the only regulations being implemented are in the transportation and electricity sectors.

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

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

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

In general, there is some uncertainty with regard to the impacts of federal or provincial climate change and environmental laws and regulations, as it is currently not possible to predict the extent of future requirements. Any new laws and regulations, or additional requirements to existing laws and regulations, could have a material impact on the Company's operations and cash flow.

Alberta

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

On June 25, 2015, the Government of Alberta renewed the *SGER* for a period of two years with significant amendments while Alberta's newly formed Climate Advisory Panel conducted a comprehensive review of the province's climate change policy. As of 2015, Regulated Emitters are required to reduce their emissions intensity by 2% from their baseline in the fourth year of commercial operation, 4% of their baseline in the fifth year, 6% of their baseline in the sixth year, 8% of their baseline in the seventh year, 10% of their baseline in the eighth year, and 12% of their baseline in the ninth or subsequent years. These reduction targets will increase, meaning that Regulated Emitters in their ninth or subsequent years of commercial operation must reduce their emissions intensity from their baseline by 15% in 2016 and 20% in 2017.

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

On November 22, 2015, as a result of the Climate Advisory Panel's Climate Leadership report, the Government of Alberta announced its Climate Leadership Plan. On June 7, 2016, the *Climate Leadership Implementation Act* ("***CLIA***") was passed into law. The *CLIA* enacted the *Climate Leadership Act* ("***CLA***") introducing a carbon tax on all sources of GHG emissions, subject to certain exemptions. An initial economy-wide levy of $20 per tonne was implemented on January 1, 2017, increasing to $30 per tonne in January of 2018. All fuel consumption—including gasoline and natural gas—will be subject to the levy, with certain exemptions, and directors of a corporation may be held jointly and severally liable with a corporation when the corporation fails to remit an owed carbon levy. Regulated Emitters will remain subject to the SGER framework until the end of 2017 and are exempt from paying the carbon levy on fuels used in operations until this time. Upon the expiry of the SGER, the Government of Alberta intends to transition to a proposed *Carbon Competitiveness Regulation*, in which sector specific output-based carbon allocations will be used to ensure competitiveness. A 100 megatonne per year limit for GHG emissions was implemented for oil sands operations, which currently emit roughly 70 megatonnes per year. This cap exempts new upgrading and cogeneration facilities, which are allocated a separate 10 megatonne limit.

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

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

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

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

British Columbia

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

Further, on April 3, 2008, the Government of British Columbia introduced the *Greenhouse Gas Reduction (Cap and Trade) Act* (the "**Cap and Trade Act**"), which received royal assent on May 29, 2008 and partially came into force by regulation of the Lieutenant Governor in Council. It sets a province-wide target of a 33% reduction in the 2007 level of GHG 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 GHG 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 GHGs has since been streamlined by the *Greenhouse Gas Industrial Reporting and Control Act* (the "*GGIRCA*") and its associated regulations that came into force on January 1, 2016. The GGIRCA sets out benchmarked performance standards for different industrial facilities and sectors, provides for emissions offsets through the purchase of emission credits or emission offsetting projects, among other measures, and replaces the *Cap and Trade Act*.

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

On August 19, 2016, the Government of British Columbia unveiled its Climate Leadership Plan with a goal to reduce net annual GHG emissions by up to 25 million tonnes below current forecasts by 2050, and reaffirmed that it will achieve its 2050 target of an 80% reduction in emissions from 2007 levels. In addition to various measures across the economy that are designed to incentivize the growth of the renewable energy sector, the use of low GHG emitting technologies, and the improvement of energy efficiency, among other goals, the Government of British Columbia will soon implement a formal policy to regulate carbon capture and storage projects. Further, the Climate Leadership Plan sets out a strategy to reduce methane emissions in the upstream natural gas sector, beginning with a Legacy phase that targets a 45% 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.

STATEMENT OF RESERVES AND OTHER OIL AND NATURAL GAS INFORMATION

In accordance with National Instrument 51-101 - *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101") and Canadian Oil and Gas Evaluation Handbook reserve definitions, McDaniel & Associates Consultants Ltd. ("McDaniel") prepared a report for the Company dated February 10, 2017 with an effective date of December 31, 2016 (the "McDaniel Report"). The McDaniel Report evaluated Hemisphere's oil, NGL and natural gas reserves. All properties evaluated are in Canada and specifically in Alberta and British Columbia. The Reserves Committee of the Board of Directors has reviewed and approved the McDaniel Report. The *Report on Reserves Data by the Independent Qualified Reserves Evaluator* and *Report of Management and Directors on Oil and Gas Disclosure* are attached as Appendices "A" and "B" hereto, respectively.

The tables below are a summary of the oil, NGL and natural gas reserves attributable to Hemisphere's properties and the net present values of future net revenue attributable to such reserves as evaluated in the McDaniel Report based on forecast price and certain cost assumptions. The tables summarize the data contained in the McDaniel Report and, as a result, may contain slightly different numbers than such report due to rounding. Also, due to rounding, certain columns may not add exactly.

The net present values of future net revenue attributable to reserves is stated without provision for interest costs and general and administrative costs, but after providing for estimated royalties, production costs, development costs, other income, future capital expenditures, and well abandonment costs for only those wells assigned reserves by McDaniel. It should not be assumed that the undiscounted or discounted net present values of future net revenue attributable to reserves estimated by McDaniel represent the fair market value of those reserves. Other assumptions and qualifications relating to costs, prices for future production and other matters are summarized herein. The recovery and reserve estimates of oil, NGL, and natural gas reserves provided herein are estimates only. Actual reserves may be greater than or less than the estimates provided herein.

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

The reserves of the Company and the estimated net present value of the future net revenue of the Company's reserves set forth in the tables above reflect the royalty regime in place for the Province of Alberta as of the effective date of the McDaniel Report being December 31, 2016 and reflect the Modernized Royalty Framework released by the Government of Alberta on January 29, 2016. See "*Industry Conditions – Royalties and Incentives – Alberta*".

Readers should review the definitions and information contained in "*Additional Information Relating to Reserve Data*" below in conjunction with the following tables and notes. The recovery and reserve estimates on Hemisphere's properties described herein are estimates only. The actual reserves on Hemisphere's properties may be greater or less than those calculated. See "*Risk Factors*".

Summary of Oil and Natural Gas Reserves and Net Present Values of Future Net Revenue
As of December 31, 2016
Forecast Prices and Costs

	Heavy Crude Oil		**Conventional Natural Gas**	
Reserves Category	Gross[1] (Mbbl)	Net[2] (Mbbl)	Gross[1] (MMcf)	Net[2] (MMcf)
Proved				
Developed Producing	1,597.8	1374.0	657.9	596.3
Developed Non-Producing	100.8	94.1	32.3	28.0
Undeveloped	1,306.6	1,193.1	124.5	112.4
Total Proved	**3,005.3**	**2,661.2**	**814.8**	**736.7**
Total Probable	1,359.6	1,182.8	381.8	346.6
Total Proved Plus Probable	**4,364.8**	**3,844.0**	**1,196.6**	**1,083.2**

Notes:
(1) Gross reserves are the Company's working interest reserves before royalty deductions.
(2) Net reserves are the Company's working interest reserves after royalty deductions plus any royalty interest reserves.

Net Present Values of Future Net Revenue
Before Income Taxes Discounted at (%/year)

Reserves Category	0% M$	5% M$	10% M$	15% M$	20% M$	Unit Value Before Income Tax Discounted at 10% per year $/boe[1]
Proved						
Developed Producing	47,112.8	36,766.6	30,026.3	25,396.2	22,058.4	17.59
Developed Non-Producing	1,829.0	1,575.2	1,350.5	1,163.3	1,009.9	12.71
Undeveloped	24,632.5	18,736.3	14,304.6	10,942.9	8,351.7	10.78
Total Proved	**73,574.3**	**57,078.1**	**45,681.4**	**37,502.4**	**31,420.0**	**14.54**
Probable	46,968.4	29,399.0	20,221.0	14,840.0	11,389.4	14.21
Total Proved Plus Probable	**120,542.7**	**86,477.1**	**65,902.4**	**52,342.3**	**42,809.5**	**14.44**

Note:
(1) The unit values are based on working interest volumes.

Net Present Values of Future Net Revenue
After Income Taxes Discounted at (%/year)

	0% M$	5% M$	10% M$	15% M$	20% M$
Proved					
Developed Producing	46,701.1	36,596.9	29,952.9	25,363.1	22,042.9
Developed Non-Producing	1,335.0	1,322.2	1,216.9	1,090.7	969.4
Undeveloped	17,876.4	13,853.6	10,687.7	8,203.4	6,235.3
Total Proved	**65,912.5**	**51,772.8**	**41,857.5**	**34,657.1**	**29,247.6**
Probable	34,477.1	21,539.2	14,789.3	10,845.9	8,324.0
Total Proved Plus Probable	**100,389.7**	**73,311.9**	**56,646.8**	**45,503.0**	**37,571.6**

Total Future Net Revenue
(Undiscounted)
As of December 31, 2016
Forecast Prices and Costs

Reserves Category	Revenue[(1)] M$	Royalties[(2)] M$	Operating Costs M$	Development Costs M$	Abandon-ment & Reclamation Costs[(3)] M$	Future Net Revenue Before Income Taxes M$	Income Taxes M$	Future Net Revenue After Income Taxes M$
Total Proved	198,424	22,283	79,809	19,124	3,634	73,574	7,662	65,913
Total Proved plus Probable	305,187	35,808	122,479	22,050	4,308	120,543	20,153	100,390

Notes:
(1) Includes all product revenues and other revenues as forecast.
(2) Royalties includes any net profits interests paid.
(3) Abandonment and reclamation costs have only been included by McDaniel for wells (both existing and undrilled wells) with reserves attributed. No allowance was made, however, for the abandonment and reclamation costs in respect of any facilities, pipelines or for any wells that have not been attributed with reserves. See "Abandonment and Reclamation Costs" below.

Future Net Revenue by Product Type
As of December 31, 2016
Forecast Prices and Costs

Reserves Category	Product Type	Future Net Revenue Before Income Taxes (discounted at 10%) M$	Unit Value[(1)] $/bbl	Unit Value[(1)] $/Mcf
Proved	Heavy Crude Oil (including solution gas and by-products)	45,704	17.17	
	Conventional Natural Gas (including by-products but excluding solution gas from oil wells)	(23)		(2.86)
	Total	**45,681**		
Proved Plus Probable	Heavy Crude Oil (including solution gas and by-products)	65,942	17.15	
	Conventional Natural Gas (including by-products but excluding solution gas from oil wells)	(40)		(0.47)
	Total	**65,902**		

Notes:
(1) Unit values are calculated using the 10% discount rate divided by the net reserves for each product type.

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 forecast pricing, inflation and exchange rates utilized in the McDaniel Report were as follows:

Summary of Pricing and Inflation Rate Assumptions
Forecast Prices and Costs
As at January 1, 2017

	Oil			**Natural Gas**		
Year	WTI Crude Oil ($US/bbl)	Edmonton Light Crude Oil ($Cdn/bbl)	Western Canadian Select Crude Oil ($Cdn/bbl)	Alberta AECO Spot Price ($Cdn/MMBtu)	Inflation (%)	US/Cdn Exchange Rate ($US/$Cdn)
2017	55.00	69.80	53.70	3.40	0	0.750
2018	58.70	72.70	58.20	3.15	2.0	0.775
2019	62.40	75.50	61.90	3.30	2.0	0.800
2020	69.00	81.10	66.50	3.60	2.0	0.825
2021	75.80	86.60	71.00	3.90	2.0	0.850
2022	77.30	88.30	72.40	3.95	2.0	0.850
2023	78.80	90.00	73.80	4.10	2.0	0.850
2024	80.40	91.80	75.30	4.25	2.0	0.850
2025	82.00	93.70	76.80	4.30	2.0	0.850
2026	83.70	95.60	78.40	4.40	2.0	0.850
2027	85.30	97.40	79.90	4.50	2.0	0.850
2028	87.00	99.40	81.50	4.60	2.0	0.850
2029	88.80	101.40	83.10	4.65	2.0	0.850
2030	90.60	103.50	84.90	4.75	2.0	0.850
2031	92.40	105.50	86.50	4.85	2.0	0.850
Thereafter		Escalation Rate of 2%/year			2.0	0.850

The weighted average sales prices realized by Hemisphere for the year ended December 31, 2016 were $35.67/bbl for heavy crude oil, $29.08/bbl for NGLs and $1.96/Mcf for conventional natural gas.

Reserves Reconciliation

Reconciliation of Gross Reserves
By Product Type
Forecast Prices and Costs

	Heavy Crude Oil			Conventional Natural Gas			Natural Gas Liquids			Boe		
	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (Mboe)	Probable (Mboe)	Proved Plus Probable (Mboe)
Dec. 31, 2015	**2,659.2**	**1,082.8**	**3,742.0**	**755.3**	**395.8**	**1,151.1**	**-**	**-**	**-**	**2,785.1**	**1,148.8**	**3,933.9**
Extensions and improved recovery	209.7	239.5	449.2	-	-	-	-	-	-	209.7	239.5	449.2
Infill Drilling	-	-	-	-	-	-	-	-	-	-	-	-
Technical Revisions	231.6	3.2	234.9	206.6	(18.9)	187.7	0.7	-	0.7	266.8	0.1	266.9
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-
Acquisitions	69.5	34.0	103.4	18.4	4.9	23.2	-	-	-	72.5	34.8	107.3
Dispositions	-	-	-	-	-	-	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-	-	-	-	-	-	-
Production	164.7	-	164.7	165.4	-	165.4	0.7	-	0.7	193.0	-	193.0
Dec. 31, 2016	**3,005.3**	**1,359.6**	**4,364.8**	**814.8**	**381.8**	**1,196.6**	**-**	**-**	**-**	**3,141.1**	**1,423.2**	**4,564.3**

Undeveloped Reserves

Undeveloped reserves were attributed in accordance with the standards and procedures in the Canadian Oil and Gas Evaluation Handbook.

The following tables set forth the remaining proved undeveloped reserves and the remaining probable undeveloped reserves, each by product type, attributed to the Company's assets for the years ended December 31, 2016, 2015, and 2014 based on forecast prices and costs.

	Heavy Crude Oil		Conventional Natural Gas	
	First Attributed Gross (Mbbl)	Cumulative at Year End Gross (Mbbl)	First Attributed Gross (MMcf)	Cumulative at Year End Gross (MMcf)
Proved Undeveloped				
December 31, 2014	468.5	820.2	371.0	405.6
December 31, 2015	541.5	1,012.2	187.2	226.0
December 31, 2016	209.7	1,306.6	0	124.5
Probable Undeveloped				
December 31, 2014	365.5	571.9	227.6	238.2
December 31, 2015	191.3	440.4	73.7	84.8
December 31, 2016	239.5	693.0	0	39.4

Proved undeveloped reserves are generally those reserves related to infill wells that have not yet been drilled or wells further away from gathering systems requiring relatively high capital to bring on production. Probable undeveloped reserves are generally those reserves tested or indicated by analogy to be productive, infill drilling locations and lands contiguous to production. This also includes the probable undeveloped wedge from the proved undeveloped locations.

The Company currently plans to pursue the development of its proven and probable undeveloped reserves within the next two years through ordinary course capital expenditures. However, a number of factors could result in delayed or cancelled development (including the delay or development of the undeveloped reserves beyond two years from the date such undeveloped reserves are first attributed) which may include:

- impact of commodity prices as a substantial and extended decline in the price of oil and natural gas would have an adverse effect on, among other things, the Company's revenues and financial condition and consequently, its ability to finance the development of its undeveloped reserves;

- other changing economic conditions (due to royalties, operating and capital expenditure fluctuations);

- changing technical conditions (production anomalies (such as water breakthrough, accelerated depletion));

- multi-zone developments (such as a prospective formation completion may be delayed until the initial completion is no longer economic);

- a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and

- surface access issues (landowners, weather conditions, regulatory approvals)

Significant Factors or Uncertainties Affecting Reserves Data

The process of evaluating reserves is inherently complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserves estimates contained herein are based on current production forecasts, prices and economic conditions and other factors and assumptions that may affect the reserves estimates and the present worth of the future net revenue therefrom. These factors and assumptions include, among others: (i) historical production in the area compared with production rates from analogous producing areas; (ii) initial production rates; (iii) production decline rates; (iv) ultimate recovery of reserves; (v) success of future development activities; (vi) marketability and pricing of production; (vii) effects of government regulations; and (viii) other government levies imposed over the life of the reserves.

As circumstances change and additional data becomes available, reserves estimates also change. Estimates are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, product pricing, capital expenditures, operating costs, royalty regimes, abandonment and reclamation costs and well performance, all of which are beyond the control of the Company. These revisions can be either positive or negative.

With regard to the particular components of the Reserves Data, the Company does not anticipate any unusually high development costs or operating costs, nor does the Company have any contractual obligations to produce and sell a significant portion of production at prices substantially below those which could be realized but for those contractual obligations.

See also "*Pricing Assumptions*", "*Abandonment and Reclamation Costs*" and "*Risk Factors*".

Abandonment and Reclamation Costs

As at December 31, 2016, Hemisphere had 98.2 net wells for which abandonment and reclamation costs are expected to be incurred. There are no unusually significant abandonment and reclamation costs associated with our properties with or without reserves assigned.

In estimating the future net revenues disclosed in this AIF, the McDaniel Report deducted: (i) $4.3 million (undiscounted) and $0.7 million (10% discount) for abandonment and reclamation costs for all wells included in the proved plus probable reserves category; and (ii) $3.6 million (undiscounted) and $0.8 million (10% discount) for abandonment and reclamation costs for all wells included in the proved reserves category. The abandonment and reclamations costs that are deducted from the future net revenues disclosed in this AIF do not contain an allowance for abandonment and reclamation costs for facilities, pipelines or for any wells that have not been attributed with reserves, which management has estimated to be an additional $3.4 million (undiscounted) and $0.6 million (10% discount).

Future Development Costs

The table below sets out the development costs deducted in the estimation of future net revenue attributable to the reserves categories noted below.

	Forecast Prices and Costs	
	Proved Reserves M$	Proved Plus Probable Reserves M$
2017	12,755	14,555
2018	5,574	5,574
2019	796	1,921
2020	-	-
Remaining	-	-
Total (Undiscounted)	**19,124**	**22,050**

Hemisphere typically has available three sources of funding to finance its capital expenditure program: internally generated cash flow from operations, debt financing when appropriate and new equity issues, if available on favourable terms.

ADDITIONAL INFORMATION RELATING TO RESERVES DATA

The determination of oil and natural gas reserves involves the preparation of estimates that have an inherent degree of associated uncertainty. Categories of Proved and Probable reserves have been established to reflect the level of these uncertainties and to provide an indication of the probability of recovery.

The estimation and classification of reserves requires the application of professional judgment combined with geological and engineering knowledge to assess whether or not specific reserves classification criteria have been satisfied. Knowledge of concepts, including uncertainty and risk, probability and statistics, and deterministic and probabilistic estimation methods, is required to properly use and apply reserve definitions.

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

"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 capital expenditure (e.g. when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

"fair market value" means the price at which a purchaser seeking an economic and commercial return on investment would be willing to buy, and a vendor would be willing to sell, where neither is under compulsion to buy or sell and both are competent and have reasonable knowledge of the facts.

"future net revenue" means the estimated net amount to be received with respect to the development and production of reserves (including synthetic oil, coal bed methane and other non-conventional reserves) estimated using constant prices and costs or forecast prices and costs.

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

"gross" means:

(a) in relation to the Company's interest in production or reserves, its "Company gross reserves", which are the Company's interest (operating and non-operating) share before deduction of royalties and without including any royalty interest of the Company;
(b) in relation to wells, the total number of wells in which the Company has an interest; and
(c) in relation to properties, the total area of properties in which the Company has an interest.

"**heavy crude oil**" means crude oil with a relative density greater than 10 degrees API gravity and less than or equal to 22.3 degrees API gravity.

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

"net" means:

(a) in relation to the Company's interest in production or reserves, its working interest (operating or non-operating) share after deduction of royalty obligations, plus the Company's royalty interest in production or reserves;
(b) in relation to the Company's interest in wells, the number of wells obtained by aggregating the Company's working interest in each of its gross wells; and

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

"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.

"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.

"solution gas" means gas dissolved in crude oil.

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

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

OTHER OIL AND GAS INFORMATION

Description of Oil and Gas Properties

Hemisphere's oil and gas properties at December 31, 2016 are located in Alberta and British Columbia. The following map identifies the location of the Company's assets:

Core Assets

The Company has two producing core assets located in southeast Alberta.

Jenner

Jenner is located 100 kilometres northwest of Medicine Hat. Hemisphere first entered the area in 2010 and owns 26,280 gross acres (23,811 net acres) as of December 31, 2016. The property has eight oil pools defined by 3D seismic. There are two, Hemisphere-owned-and-operated, oil processing and water disposal facilities in Jenner with the capability for expansion.

At December 31, 2016, the McDaniel Report assigned total proved plus probable reserves of 1,498.4 Mbbl of heavy crude oil and 496.6 MMcf of conventional natural gas to the Company's Jenner property area. The Company held an interest in 21,240 gross acres (20,051 net acres) of undeveloped land in the Jenner area as of December 31, 2016.

Atlee Buffalo

Atlee Buffalo is located 25 kilometres northeast of Jenner. Hemisphere made its first acquisition in the area in late 2013 and owns 7,040 gross acres (7,040 net acres) as of December 31, 2016. The property has two oil pools delineated by vertical wells and defined by 3D seismic.

At December 31, 2016, the McDaniel Report assigned total proved plus probable reserves of 2,816.4 Mbbl of heavy crude oil and 610.5 MMcf of conventional natural gas to the Company's Atlee Buffalo property area. The Company held an interest in 5,600 gross acres (5,600 net acres) of undeveloped land in the Atlee Buffalo area as of December 31, 2016.

Non-core Assets

Trutch (Tommy Lakes) is located 250 kilometres northwest of Fort St. John, British Columbia. The Company owns 35,612 gross acres (21,525 net acres) as of December 31, 2016, which includes non-operated wells producing liquids rich natural gas. At December 31, 2016, the McDaniel Report assigned no economic reserves for this property. The Company held an interest in 31,727 gross acres (20,355 net acres) of undeveloped land in the Trutch area as of December 31, 2016.

Hemisphere also has various working interests in three other non-core assets located in southern Alberta (Sylvan Lake, Heathdale, and Wainright). At December 31, 2016, the McDaniel Report assigned total proved plus probable reserves of 50 Mbbl of heavy crude oil and 89.5 MMcf of conventional natural gas to the Company's non-core assets. The Company held an interest in 4,480 gross acres (2,648 net acres) of land, of which 1,920 gross/net acres are undeveloped in its non-core asset property areas as of December 31, 2016.

Oil and Natural Gas Wells

The following table summarizes Hemisphere's interest as at December 31, 2016 in wells that are producing and non-producing:

	Producing Wells(1)				**Non-Producing Wells(1)**			
	Oil		Natural Gas		Oil		Natural Gas	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta								
Atlee Buffalo	9	9	0	0	6	6	4	4

Jenner	11	11	-	-	17	17	5	5
Sylvan Lake	-	-	4	0.6	-	-	7	1.85
Wainwright	-	-	-	-	-	-	1	0.6875
British Columbia								
Trutch	-	-	4	1.4	-	-	1	0.5
Total	**20**	**20**	**8**	**2**	**23**	**23**	**18**	**12.0375**

Note:

(1) Does not include injection, disposal, source, observation, or abandoned wells.

(2) The Company has attributed reserves to 17% of its non-producing oil wells and to approximately 6% of its non-producing natural gas wells. The reserves attributed to these non-producing wells represent 4% of the Company's total proved (net) reserves. Each of these non-producing wells are tied into of existing pipeline and/or facility infrastructure. The period for which these non-producing wells have been off of production varies from approximately 1 year to several years.

(3) The non-producing wells currently capable of production that are not currently producing will be considered to be placed on production, from time to time, with respect to future product prices, proximity to facility infrastructure, design of future exploration and development programs and access to capital.

Exploration and Drilling Activities

Hemisphere drilled one development oil well during the year ended December 31, 2016.

Production History

	Three Months Ended				Year Ended
	Mar. 31, 2016	Jun. 30, 2016	Sept. 30, 2016	Dec. 31, 2016	Dec. 31, 2016
Average daily production					
Heavy Crude Oil (bbl/d)	409	407	450	534	450
Conventional Natural Gas (Mcf/d)	581	499	400	330	452
NGL (bbl/d)	2	2	2	1	2
Combined (boe/d)	508	492	518	590	527
Average sales prices					
Heavy Crude Oil (bbl/d)	22.39	37.59	37.28	42.91	35.67
Conventional Natural Gas (Mcf/d)	1.86	1.13	2.24	3.05	1.96
NGL (bbl/d)	19.21	26.73	32.88	46.32	29.08
Combined ($/boe)	20.24	32.34	34.19	40.63	32.23
Operating netback ($/boe)					
Petroleum and natural gas Revenue	20.24	32.34	34.19	40.63	32.23
Royalties	2.36	2.38	4.64	4.64	3.57
Operating costs	11.45	12.18	7.92	17.52	12.46
Transportation costs	3.70	4.81	5.27	2.61	4.04
Operating netback	2.73	12.97	16.36	15.85	12.16

Note:

(1) Operating netback is calculated by subtracting royalties and operating costs from revenue, net of transportation costs.

Production Estimates

The following table discloses, by product type, the total volume of production estimated by McDaniel for the year ending December 31, 2017 in the estimates of future net revenue from Proved and from Probable Reserves disclosed under *"Petroleum and Natural Gas Reserves"*.

Proved	**Heavy Crude Oil** (bbl/d)	**Conventional Natural Gas** (Mcf/d)	**Total** (boe/d)
Alberta			

Atlee Buffalo	583.3	99.2	599.8
Heathdale	-	-	-
Jenner	257.8	166.3	285.5
Sylvan Lake	-	15.3	2.6
Wainwright	-	-	-
British Columbia			
Trutch	-	-	-
Total	**841.4**	**280.8**	**888.2**

Proved Plus Probable	**Heavy Crude Oil** (bbl/d)	**Conventional Natural Gas** (Mcf/d)	**Total** (boe/d)
Alberta			
Atlee Buffalo	644.4	99.2	660.9
Heathdale	-	-	-
Jenner	266.6	172.1	295.3
Sylvan Lake	-	15.3	2.6
Wainwright	-	-	-
British Columbia			
Trutch	-	-	-
Total	**911.0**	**286.6**	**958.8**

Developed and Undeveloped Lands

The following table summarizes, by province, Hemisphere's developed and undeveloped landholdings as at December 31, 2016:

	Developed Acres		**Undeveloped Acres**		**Total Acres**	
	Gross	Net	Gross	Net	**Gross**	**Net**
Alberta						
Atlee Buffalo	1,440	1,440	5,600	5,600	**7,040**	**7,040**
Heathdale	-	-	1,920	1,920	**1,920**	**1,920**
Jenner	5,040	3,760	21,240	20,051	**26,280**	**23,811**
Sylvan Lake	1,920	288	-	-	**1,920**	**288**
Wainwright	640	440	-	-	**640**	**440**
British Columbia						
Trutch	3,885	1,170	31,727	20,355	**35,612**	**21,525**
Total	**12,925**	**7,098**	**60,487**	**47,926**	**73,412**	**55,024**

The following table summarizes Hemisphere's unproven lands for which the Company expects its rights to explore, develop and exploit are scheduled to expire in 2017, if not continued:

	Acreage	
Location	Gross	Net
Atlee Buffalo	920	920
Jenner	800	800
Trutch	35,612	22,065
Heathdale	640	640

The Company plans to drill or submit applications to continue portions of the above acreage.

Significant Factors or Uncertainties Relevant to Properties with No Attributed Reserves

Changes in future commodity prices could have a negative impact on the development of the Company's properties with no attributed reserves. See "Risk Factors" in this AIF for further discussion of economic and risk factors relevant to the Company's properties with no attributed reserves.

The Company does not anticipate any significant abandonment and reclamation costs or any unusually high development or operating costs that have affected or are reasonably expected to affect the anticipated development or production activities on the Company's properties which have no attributed reserves, nor does the Company have any contractual obligations to produce or sell a significant portion of production at prices substantially below those which could be realized but for those contractual obligations.

Forward Contracts

As at December 31, 2016, Hemisphere did not have any hedging or marketing arrangements that could materially impact the Company's realized sales price that have not been disclosed as financial instruments in its financial statements.

Tax Horizon

Hemisphere was not required to pay income taxes during the year ended December 31, 2016 and has approximately $49 million of tax pools available to be applied against future income for tax purposes. Based on available pools and current commodity prices, the Company does not expect to pay income tax in 2016 or 2017. Taxes payable beyond 2017 will primarily be a function of commodity prices, capital expenditures, and production volumes.

Costs Incurred

The following table summarizes Hemisphere's property acquisition costs, exploration costs and development costs for the year ended December 31, 2016:

	Property Acquisition Costs			
	Proved Properties	Unproved Properties	Exploration Costs	Development Costs
Total	**-**	**-**	**-**	**2,722,375**

DIVIDENDS

Hemisphere has not declared or paid any dividends since its incorporation. The future payments of dividends will depend on the earnings and financial condition of the Company and such other factors as the Board of Directors of the Company consider appropriate. See "*Risk Factors – Dividends*".

The Company would be restricted from issuing dividends in the event that paying any such dividend would cause a breach of the financial covenants under its Credit Facility.

SHARE CAPITAL

Common Shares

Hemisphere has an unlimited number of common shares authorized. As of the date of this AIF there are 85,745,102 common shares issued and outstanding. Holders of Hemisphere's common shares are entitled to notice of meetings and one vote per share at meetings of the Company's shareholders, to dividends if, as and when declared by the Board of Directors, and upon liquidation, dissolution or winding-up, to receive the Company's remaining property.

Stock Options

The Company has a stock option plan in place and is authorized to grant stock options to officers, directors, employees and consultants whereby the aggregate number of shares reserved for issuance may not exceed 10% of the issued common shares at the time of grant and 5% of the issued common shares to each optionee. Stock options are non-transferable, and have a five-year term or a maximum 10 year term as regulated by the TSX-V for Tier 1 issuers. Stock options terminate not later than 90 days upon termination of employment/contract and one year in the case of retirement/death/disability. The grant price is determined using the closing price of the Company's shares on the day prior to the grant.

As of the date of this AIF the Company had 2,985,000 stock options outstanding.

Warrants

As of the date of this AIF, the Company did not have any warrants outstanding.

MARKET FOR SECURITIES

The common shares of the Company are listed for trading on the TSX-V under the symbol "HME".

Common Share Trading

	Price Range		
	High	Low	Total Volume Traded
2016			
January	0.10	0.05	3,430,300
February	0.15	0.07	1,704,400
March	0.22	0.14	1,970,100
April	0.20	0.13	2,769,300
May	0.22	0.14	4,397,700
June	0.24	0.17	3,936,500
July	0.28	0.18	2,344,300
August	0.21	0.16	1,382,000
September	0.20	0.14	1,017,000
October	0.21	0.15	1,457,700
November	0.17	0.13	1,770,800
December	0.17	0.14	5,159,400
2017			
January	0.28	0.16	4,435,500
February	0.33	0.26	3,632,000
March	0.30	0.19	2,400,039
April 1 to 18	0.28	0.25	462,500

PRIOR SALES

The following table sets forth, for each class of securities of the Company that is outstanding but not listed or quoted on a marketplace, the price at which securities of the class have been issued during the fiscal year ended December 31, 2016 and the number of securities of the class issued at that price and the date on which the securities were issued.

Date	Type of Securities	Number of Securities Outstanding	Exercise Price	Expiry Date
February 11, 2016	Stock Options	1,610,000	$0.08	February 11, 2021
February 12, 2016	Stock Options	200,000	$0.08	February 12, 2021

ESCROWED SECURITIES AND SECURITIES SUBJECT TO CONTRACTUAL RESTRICTION ON TRANSFER

To the knowledge of the directors and executive officers of Hemisphere, none of the securities of Hemisphere are held in escrow or are subject to a contractual restriction on transfer as at the date of this AIF.

DIRECTORS AND OFFICERS

The names, municipalities of residence, any offices held with Hemisphere, the period served as a director and principal occupations of the Company's directors and officers are set out below:

Name and Municipality of Residence	Position with Hemisphere	Director or Officer Since	Principal Occupation During the Past Five Years
Don Simmons, P. Geol.(1)(3) Vancouver, British Columbia, Canada	President and Chief Executive Officer Director	February 2008 May 2008	Previously Vice President Exploration of the Company from October 2007. Formerly, a Geologist at Sebring Energy Inc., Encana Corporation and Alberta Energy Company.
Charles O'Sullivan, B.Sc.(2)(3) Vancouver, British Columbia, Canada	Chairman Director	2000 1978	Geophysicist and Mining Executive. Chairman of Northern Continental Resources Inc. from 1986 to 2009.
Frank Borowicz, QC, CA (Hon)(2)(3)(4) Surrey, British Columbia, Canada	Director	July 2005	President of Pigasus Consulting Services Ltd.
Bruce McIntyre, P.Geol.(1)(2)(4) Calgary, Alberta, Canada	Director	July 2008	Most recently Executive Director of New Zealand Energy Corp. until June 2014 and previously President from April 2011 to July 2012. From 2007 to 2011, an independent consultant and President of Wexford Energy Ltd., a private company that provides consulting services for the development and operation of producing natural gas companies (private and public).
Gregg Vernon, P. Eng.(1)(4) Bogota, Cundinamarca, Colombia	Director	August 2006	Currently, President of PMI Resources Ltd. President of Bochica Oil & Gas Inc. Previously, Interim President and Chief Executive Officer of Petrodorado Energy Ltd. from October 2013 to February 2015. Prior thereto, Interim Chief Operating Officer of Petro Magdalena Energy Corp. (formerly Alange Energy Corp.) from January 2011 to its sale in July 2012.
Richard Wyman, B.Sc., MBA(1)(4) Calgary, Alberta, Canada	Director	October 2014	President and Director of Northern Cross (Yukon) Ltd. since October 2010.
Ian Duncan, P. Eng. Vancouver, British Columbia, Canada	Chief Operating Officer	May 2011	Appointed Chief Operating Officer in September 2014. Previously Vice President, Engineering since May 2011 and an engineer with Hemisphere since January 2011. Prior thereto, an engineer at Solaris MCI and Talisman Energy Inc.
Dorlyn Evancic, CGA	Chief Financial	July 2007	Previously Chief Financial Officer of

Port Coquitlam, British Columbia, Canada	Officer		Northern Continental Resources Inc. from July 2007 to November 2009. From December 2010 to November 2011, Chief Financial Officer of Guyana Frontier Mining Corp.
Andrew Arthur, P. Geol. Delta, British Columbia, Canada	Vice President, Exploration	July 2012	A consultant for Hemisphere from January 2012 to July 2012. From December 2008 to January 2012, Technical Lead Oil Business Unit for Enerplus Corporation.
Ashley Ramsden-Wood, P.Eng. North Vancouver, British Columbia, Canada	Vice President, Engineering	September 2014	A consulting engineer for Hemisphere from June 2012 to September 2014. From 2005 to 2011, an engineer with NAL Resources.

Notes:

(1) Member of the Reserves Committee. Bruce McIntyre is the Chairman of the Reserves Committee.

(2) Member of the Compensation/Nominating Committee. Charles O'Sullivan is Chairman of the Compensation/Nominating Committee.

(3) Member of the Corporate Governance Committee. Frank Borowicz is Chairman of the Corporate Governance Committee.

(4) Member of the Audit Committee. Bruce McIntyre is Chairman of the Audit Committee.

As at the date of this AIF, the directors and officers of the Company, as a group, owned directly or indirectly 8,755,496 common shares or approximately 10% (13% on a fully diluted basis) of the issued and outstanding common shares.

Cease Trade Orders

Other than noted below, to the knowledge of the Company, no director or executive officer of the Company is, as at the date of this AIF, or was within 10 years before the date of this AIF, a director, chief executive officer or chief financial officer of any issuer (including the Company) that: (a) was subject to 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 (b) 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. For the purposes of the above, "order" means a cease trade order, an order similar to a cease trade order or an order that denied the relevant company access to any exemption under securities legislation that was in effect for a period of more than 30 consecutive days.

Mr. Evancic was a director and officer of Gemco Minerals Inc., which had a cease trade order issued in August 2007 by the British Columbia Securities Commission for revisions required in its technical report pursuant to National Instrument 43-101 – *Standard of Disclosure for Mineral Projects*. The company fully complied with the British Columbia Securities Commission requirements and revocation of the cease trade order was issued in March 2008.

Bankruptcies

To the knowledge of the Company, no director or executive officer of the Company, or a shareholder holding a sufficient number of securities of the Company to affect materially the control of the Company: (a) is, as at the date of this AIF, or has been within the 10 years before the date of this AIF, a director or executive officer of any issuer (including the Company) that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets or (b) has, within the 10 years before the date of this AIF, 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.

Penalties or Sanctions

To the knowledge of the Company, no director or executive officer of the Company, or a shareholder holding a sufficient number of securities of the Company to affect materially the control of the Company, has been subject to (a) 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 (b) any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

Conflicts of Interest

Directors and officers of the Company 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 the Company's Board of Directors serve as directors or officers of corporations which are in competition to Hemisphere's interests. No assurances can be given that opportunities identified by such members will be provided.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

There are no legal proceedings that the Company is or was a party to, or that any of its property is or was subject of, during the last completed fiscal year, nor are any such legal proceedings known to the Company to be contemplated that involves a claim for damages, exclusive of interest and costs, exceeding 10% of the current assets of the Company.

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

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

There were no material interests, direct or indirect, of directors or executive officers of the Company, any shareholder who beneficially owns, or controls or directs, directly or indirectly, more than 10% of the outstanding common shares of the Company or any known associate or affiliate of such persons in any transactions within the three most recently completed fiscal years of the Company or during the current fiscal year which has materially affected, or would reasonably be expected to materially affect, the Company.

TRANSFER AGENT AND REGISTRAR

The Company's transfer agent and registrar is Computershare Investor Services Inc. located at 3rd floor, 510 Burrard Street, Vancouver, British Columbia V6C 3B9.

INTEREST OF EXPERTS

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a statement, report or valuation described or included in a filing, or referred to in a filing, made under National Instrument 51-102 by the Company during, or related to, the Company's most recently completed financial year other than McDaniel, the Company's independent engineering evaluators, and KPMG LLP, the Company's auditors. None of McDaniel or the "designated professionals" (as defined in Item 16.2(1.1) of Form 51-102F2 of NI 51-102 of McDaniel have or are to receive any registered or beneficial interest, direct or indirect, in any of the Company's securities or other property of the Company or of the Company's associates or affiliates, at the time McDaniel prepared the report, valuation, statement or opinion. KPMG LLP, Chartered Professional Accountants, the Company's auditors, are independent within the meaning of the Chartered Professional Accountants of Alberta Rules of Professional Conduct.

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 the Company or of any associate or affiliate of the Company.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, the Company has not entered into any material contracts within the most recently completed fiscal year or before the most recently completed fiscal year and which are still in effect, other than the Credit Facility, as outlined in *Description of the Company – History of the Company*.

AUDIT COMMITTEE INFORMATION

Charter

The Company's Audit Committee is governed by an Audit Committee Charter, the text of which is attached as Appendix "C" of this AIF.

Composition

The Company's Audit Committee consists of four directors: Bruce McIntyre (Chairman), Frank Borowicz, Gregg Vernon and Richard Wyman. As defined in National Instrument 52-110 - *Audit Committees* ("NI 52-110"), Bruce McIntyre, Frank Borowicz, Gregg Vernon, and Richard Wyman are "independent".

A member of the Audit Committee is "independent", if the member has no direct or indirect "material relationship" with the Company. A "material relationship" means a relationship which could, in the view of the Company's Board of Directors, reasonably interfere with the exercise of the member's independent judgment.

Relevant Education and Experience

NI 52-110 provides that a member of the Audit Committee is considered to be "financially literate" if he has the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexities of the issues that can reasonably be expected to be raised by the Company's financial statements.

All of the members of the Company's Audit Committee are considered to be "financially literate", as that term is defined in NI 52-110.

Bruce McIntyre, P.Geol., Chairman

Mr. McIntyre has over 35 years of oil and gas experience and a proven track record of finding quality oil and gas reserves. Mr. McIntyre was most recently Executive Director of New Zealand Energy Corp. until June 2014 and previously, President from April 2011 to July 2012. Prior thereto, Mr. McIntyre was President and Chief Executive Officer of Sebring Energy Inc., a private Alberta-based exploration and production company that was sold in July 2007. He has also held various other management positions including President, CEO and co-founder of Sommer Energy Ltd., President and CEO of TriQuest Energy Corp., President and Chief Executive Officer of BXL Energy Ltd. and Exploration Manager for Gascan Resources Ltd. Mr. McIntyre is a member of the American Association of Petroleum Geologists, has a Professional Geologist designation with the Association of Professional Engineers and Geoscientists of Alberta and an Honorary Member of the Canadian Society of Petroleum Geologists (Past President 2002). Mr. McIntyre holds a Bachelor of Science Degree in Geology (Honours) from Carleton University and an Advanced Executive Certificate in General Management from Queen's University.

Frank Borowicz, QC, CPA, CA (Hon)

Mr. Borowicz has over 35 years of experience in corporate governance and regulatory compliance. He is a retired partner of the international law firm Davis LLP (DLA Piper) and is a Governor of the Vancouver Board of Trade. He served as Chairman of the BC Industry Training Authority and is an independent director of several public and private companies. Educated at Harvard, Dalhousie and Loyola, Mr. Borowicz is a member of the Institute of Corporate Directors, is a Queen's Counsel, and an honorary Chartered Professional Accountant.

Gregg Vernon, P.Eng.

Mr. Vernon is a designated professional engineer with over 35 years of international oil and gas industry experience, including managing and administrating major projects in China, Eastern Canada and South America. He is currently the President of PMI Resources Ltd., a public company listed on the Toronto Stock Exchange (TSXV:PMI) that operates in Colombia as Pentanova Energy Corp. Previously he was interim President and Chief Executive Officer of Petrodorado Energy Ltd. from October 2013 to February 2015. Prior thereto, Mr. Vernon was the interim Chief Operating Officer of PetroMagdalena Energy Corp. (formerly Alange Energy Corp.), a Canadian-based international oil and gas exploration and production company until its sale in 2012. In October of 2007, he was a founder and Chairman of Prospero Hydrocarbons Inc., a private Canadian-based international oil and gas exploration company focused on Colombia. He is one of the founders of Petro Andina Resources Ltd., a Canadian company with operations in South America. He is a University of Alberta graduate with his degree in Engineering and is a member of the Society of Petroleum Engineers.

Richard Wyman, B.Sc., MBA

With over 30 years' experience, Mr. Wyman began his career as a reservoir engineer with Esso Resources Canada Ltd. in Calgary prior to becoming a corporate finance associate with Wood Gundy in London, England. He returned to Canada and became an analyst in the corporate finance and treasury department of Gulf Canada Limited in Calgary and Toronto, and then an oil and gas equities research analyst with Peters & Co. Ltd. Following his tenure at Peters & Co., Mr. Wyman became a founding shareholder and Director of Smart Pipeline Services Ltd. and Northern Cross (Yukon) Ltd. He returned to a capital market role as Vice President and Senior Oil and Gas Analyst with Canaccord Genuity under its rebranding process in 2004. In 2010, Mr. Wyman returned to the oil and gas industry as President and a Director of Northern Cross (Yukon) Ltd, an emerging junior oil and gas, exploration and development company with assets located in Yukon. He holds a Bachelor of Applied Science degree in Chemical Engineering (Hons) from Queen's University in 1978 and a Masters of Business Administration from the International Management Institute at the University of Geneva in 1985.

Pre-Approval Policies and Procedures

The Company's Audit Committee reviews, and if determined advisable, pre-approves engagements for non-audit services to be provided by the external auditors or any of their affiliates, together with the estimated fees for such services. See also *Appendix C – Audit Committee Charter – External Auditors*.

External Auditor Service Fees

The Company's external auditor is KPMG LLP located at 3100–205 5th Avenue SW, Calgary, Alberta T2P 4B9.

Prior to KPMG LLP, the Company's auditor was Smythe Ratcliffe, LLP, which issued its last auditor report for the year ended December 31, 2014. The change in auditors took place on September 15, 2015.

The fees paid by the Company to its external auditor in each of the last two fiscal years are as follows:

Fiscal Year Ending	Audit Fees(1)	Audit Related Fees(2)	Tax Fees(3)	All Other Fees(4)
December 31, 2016	59,000	5,000	Nil	Nil
December 31, 2015	59,000	16,500	Nil	Nil

Notes:

(1) "Audit Fees" include fees necessary to perform the annual audit and quarterly reviews of the Company's 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" include services that are traditionally performed by the auditor. These audit related services include employee benefit audits, due diligence assistance, accounting consultations on proposed transactions, internal control reviews, consultations on conversion to International Financial Reporting Standards and audit or attest services not required by legislation or regulation.

(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. Tax planning and tax advice include assistance with tax audits and appeals, tax advice related to mergers and acquisitions and requests for rulings or technical advice from tax authorities.

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

ADDITIONAL INFORMATION

Additional information relating to the Company may be found on SEDAR at www.sedar.com or Hemisphere's website at www.hemisphereenergy.ca. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of the Company's securities and securities authorized for issuance under equity compensation plans is contained in the Company's Information Circular for its most recent annual meeting of shareholders. Additional financial information is contained in the Company's audited annual financial statements and related Management's Discussion and Analysis for the year ended December 31, 2016.

Additional copies of this AIF, and any financial statements which have been issued by the Company, are available on the Company's website at www.hemisphereenergy.ca, upon request by mail at Suite 2000, 1055 West Hastings Street, Vancouver, British Columbia V6E 2E9, by email at info@hemisphereenergy.ca, by phone at (604) 685-9255, or by fax at (604) 685-9676.

APPENDIX "A"

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

February 10, 2017

Hemisphere Energy Corporation
2000, 1055 West Hastings Street
Vancouver, British Columbia
V6E 2E9

Attention: The Board of Directors of Hemisphere Energy Corporation

Re: **Form 51-101F2**
Report on Reserves Data by an Independent Qualified Reserves Evaluator
of Hemisphere Energy Corporation (the "Company")

To the Board of Directors of Hemisphere Energy Corporation (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 M$ (before income taxes, 10% discount rate)			
Independent Qualified Reserves Evaluator	**Effective Date of Evaluation Report**	**Location of Reserves**	**Audited**	**Evaluated**	**Reviewed**	**Total**
McDaniel & Associates Consultants Ltd.	December 31, 2016	Canada	-	65,902.4	-	65,902.4

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

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

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

Executed as to our report referred to above:

MCDANIEL & ASSOCIATES CONSULTANTS LTD.

(Signed) *"P.A. Welch"*
P.A. Welch, P. Eng.
President & Managing Director

Calgary, Alberta, Canada
February 10, 2017

APPENDIX "B"

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

Management of Hemisphere Energy Corporation (the "Company") are responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data.

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

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

(a) reviewed the Company'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 the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The Board of Directors has 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 judgements regarding future events, actual results will vary and the variations may be material.

s/s "Don Simmons"
Don Simmons
President & Chief Executive Officer

s/s "Dorlyn Evancic"
Dorlyn Evancic
Chief Financial Officer

s/s "Bruce McIntyre"
Bruce McIntyre
Director & Chairman of the Reserves Committee

s/s "Richard Wyman"
Richard Wyman
Director & Member of the Reserves Committee

April 19, 2017

APPENDIX "C"

Hemisphere energy corporation

AUDIT COMMITTEE CHARTER

Purpose

The Audit Committee of Hemisphere Energy Corporation ("Hemisphere") assists the Board of Directors in the oversight of its integrity in financial reporting as outlined in National Instrument 52-110 *Audit Committees* ("NI 52-110").

Composition

The Audit Committee consists of no less than three directors, each of whom is "financially literate" and "independent" as defined under NI 52-110, and is annually appointed by the Board of Directors. The Chair of the Audit Committee is appointed by the Board of Directors at the same time as the member appointment.

Mandate

- Assisting the Board of Directors in fulfilling their oversight responsibilities with respect to the review of financial statements and other relevant public disclosures, compliance with legal and regulatory requirements relating to financial reporting, the external auditors' qualifications and independence, and the performance of the internal audit function and the external auditors.
- Meeting quarterly to review and approve the quarterly financial statements and management's discussion and analysis for recommendation to the Board of Directors.
- Meeting annually to review and approve the audited annual financial statements and management's discussion and analysis for recommendation to the Board of Directors.
- Annually reviewing the performance of the external auditors.
- Nominating the external auditors for recommendation to the Hemisphere shareholders at the annual general meeting of the shareholders.
- Advising the Board of Directors on the remuneration of the external auditors based on the time required to complete the audit and preparation of the audited annual financial statements, and the difficulty of the audit and performance of the standard auditing procedures under generally accepted auditing standards and International Financial Reporting Standards.

External Auditors

Hemisphere's external auditors are the independent representatives of the shareholders, yet are also accountable to the Board of Directors and the Audit Committee. The external auditors complete their audit procedures and reviews with professional independence, free from any undue interference from management or directors. The Audit Committee directs and ensures that the management fully co-operates with the external auditors in the course of carrying out their professional duties. The Audit Committee will have access to direct communications with the external auditors, if required.

The external auditors are prohibited from providing any non-audit services to Hemisphere, without the written consent of the Audit Committee unless such non-audit services are *De Minimus* Non-Audit Services as outlined in section 2.4 of NI 52-110. In determining whether the external auditors will be granted permission to provide non-audit services, the Audit Committee is to consider that the benefits to Hemisphere from the provision of such services, outweighs the risk of any compromise to or loss of the independence of the external auditors in carrying out their auditing mandate.

Notwithstanding the above non-audit services, the external auditors are prohibited at all times from carrying out any of the following services, while they are appointed the external auditors of Hemisphere:

(a) acting as an agent of Hemisphere for the sale of all or substantially all of the undertaking of Hemisphere; and

(b) performing any non-audit consulting work for any director or senior officer of Hemisphere in their personal capacity, but not as a director, officer or insider of any other entity not associated or related to Hemisphere.

The Audit Committee has the power to terminate the services of the external auditors, with or without the approval of the Board of Directors, acting reasonably.

Internal Controls

The Board of Directors will appoint a person who is responsible for implementing internal controls and performing the role as the internal auditor ensuring such controls are adequate and effective.

Continuous Disclosure Requirements

The Board of Directors will appoint a person who is responsible for ensuring that Hemisphere's continuous reporting requirements are met and in compliance with applicable regulatory requirements.

Annual Review

The Corporate Governance Committee annually reviews the Audit Committee Charter and recommends any amendments to the Board of Directors for approval.