SPARTAN
ENERGY CORP.

Annual Information Form
Financial Year Ended December 31, 2017

Dated March 14, 2018

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CONVENTIONS

Unless otherwise indicated, references herein to "$" or "dollars" are to Canadian dollars. All financial information with respect to Spartan Energy Corp. ("**Spartan**" or the "**Corporation**") has been presented in Canadian dollars in accordance with generally accepted accounting principles in Canada. The information in this annual information form ("**Annual Information Form**") is stated as at December 31, 2017, unless otherwise indicated. For an explanation of the capitalized terms and expressions and certain defined terms, please refer to the section of this Annual Information Form titled "*Definitions*".

ABBREVIATIONS

	Oil and Natural Gas Liquids		**Natural Gas**
Bbl	barrel	Mcf	thousand cubic feet
Bbls	barrels	Mmcf	million cubic feet
BOPD	barrel of oil per day	Mcf/d	thousand cubic feet per day
Mbbl	thousand barrels	Mmcf/d	million cubic feet per day
Bbls/d	barrels per day	MMBTU	million British Thermal Units
NGLs	natural gas liquids		

Other

AECO	Alberta Energy Company's natural gas storage facility located at Suffield, Alberta.
API	an indication of the specific gravity of crude oil measured on the American Petroleum Institute gravity scale. Liquid petroleum with a specified gravity of 28° API or higher is generally referred to as light crude oil.
BOE	barrel of oil equivalent of natural gas and crude oil on the basis of 1 BOE for 6 (unless otherwise stated) Mcf of natural gas (this conversion factor is an industry accepted norm and is not based on either energy content or current prices)
BOE/D	barrel of oil equivalent per day
m^3	cubic metres
MBOE	1,000 barrels of oil equivalent
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade
$000 or M$	thousands of dollars

CONVERSION

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

To Convert From	**To**	**Multiply By**
Mcf	Cubic metres	28.174
Cubic metres	Cubic feet	35.494
Bbls	Cubic metres	0.159
Cubic metres	Bbls	6.290
Feet	Metres	0.305
Metres	Feet	3.281
Miles	Kilometres	1.609
Kilometres	Miles	0.621
Acres	Hectares	0.405
Hectares	Acres	2.471

DEFINITIONS

Wherever used in this Annual Information Form, unless the context otherwise requires, the following words and phrases shall have the meanings set forth below:

“**ABCA**” means the *Business Corporations Act* (Alberta);

“**Arrangement**” means the Plan of Arrangement completed effective as of March 31, 2014 among the Corporation, Renegade and the shareholders of Renegade pursuant to which the Corporation acquired Renegade;

“**Board of Directors**” means the board of directors of Spartan;

“**COGE Handbook**” means the “Canadian Oil and Gas Evaluation Handbook” maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter), as amended from time to time;

“**Common Share**” or “**Common Shares**” means, respectively, one or more common shares in the capital of Spartan;

“**Consolidation**” means the share consolidation on the basis of one post-consolidation Common Share for every three pre-consolidation Common Shares, as approved at the annual general and special meeting of Shareholders held on June 20, 2017;

“**Corporation**” or “**Spartan**” means Spartan Energy Corp.;

“**NAFTA**” means the North American Free Trade Agreement;

“**NEB**” means the National Energy Board;

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

“**NI 52-110**” means National Instrument 52-110 – *Audit Committees*;

“**Options**” means the stock options granted by the Corporation to purchase Common Shares;

“**Renegade**” means Renegade Petroleum Ltd.;

“**RSUs**” means the restricted share units granted by the Corporation exercisable for Common Shares for no additional consideration;

“**Shareholders**” means the holders of Common Shares;

“**Sproule**” means Sproule Associates Limited;

“**Tax Act**” means the *Income Tax Act* (Canada), R.S.C. 1985, c.1 (5th Supp.), as amended;

“**TSX**” means the Toronto Stock Exchange;

“**TSXV**” means the TSX Venture Exchange;

“**U.S.**”, “**US**” or “**United States**” means the United States of America;

“**Warrants**” means share purchase warrants issued by the Corporation, each of which entitles the holder thereof to purchase one Common Share at a price of $2.40 per Common Share, on a post-Consolidation basis; and

“**Wyatt**” means Wyatt Oil and Gas Inc.

SPECIAL NOTE REGARDING FORWARD LOOKING STATEMENTS

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

Forward-looking statements or information in this Annual Information Form include, but are not limited to, the characteristics of the Corporation's oil and natural gas interests, reserve quantities and the discounted present value of future net cash flows from such reserves, projection of market prices, capital expenditures, exploration plans, development plans, growth prospects, acquisition and disposition plans and the timing thereof, worldwide supply and demand for petroleum products, royalty rates, treatment under governmental regulatory regimes and tax laws, future revenues and costs (including royalties) and revenues and costs per commodity unit, oil and natural gas production levels, ability to meet current and future obligations, future tax liabilities and future use of tax pools and losses, future decommissioning costs, the ability to obtain financing on acceptable terms or at all and currency, exchange and interest rates. In addition, this Annual Information Form may contain forward-looking statements attributed to third party industry sources.

With respect to forward-looking statements contained in this Annual Information Form, the Corporation has made assumptions regarding, among other things:

- the legislative and regulatory environments of the jurisdictions where the Corporation carries on business or has operations;
- commodity prices and royalty regimes;
- the impact of increasing competition;
- availability of skilled labour;
- timing and amount of capital expenditures;
- the price of oil and natural gas;
- conditions in general economic and financial markets;
- royalty rates and future operating costs; and
- the Corporation's ability to obtain additional financing on satisfactory terms.

Spartan's actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and elsewhere in this Annual Information Form:

- general economic conditions in Canada and globally;
- the ability of management to execute its business plan;
- fluctuations in the price of oil and natural gas, interest and exchange rates;
- risks inherent in the oil and gas industry, such as operational risks and market demand;
- governmental regulation of the oil and gas industry, including environmental regulation;
- uncertainty in amounts and timing of royalty payments;
- actions taken by governmental authorities, including increases in taxes and changes in government regulations and incentive programs;

- geological, technical, drilling and processing problems;
- exploration and development activities are capital intensive and involve a high degree of risk;
- risks and uncertainties involving geology of oil and gas deposits;
- risks inherent in marketing operations, including credit risk;
- the uncertainty of reserves estimates and reserves life;
- the uncertainty of estimates and projections relating to production, costs and expenses;
- potential delays or changes in plans with respect to exploration or development projects or capital expenditures;
- availability of sufficient financial resources to fund the Corporation's capital expenditures;
- unanticipated operating events which could reduce production or cause production to be shut-in or delayed;
- hazards such as fire, explosion, blowouts, cratering and spills, each of which could result in substantial damage to wells, production facilities, other property and the environment or in personal injury;
- encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations;
- the ability to add production and reserves through development and exploration activities;
- the possibility that government policies or laws, including laws and regulations related to the environment, may change or governmental approvals may be delayed or withheld;
- uncertainties inherent in estimating quantities of oil and natural gas reserves and cash flows to be derived therefrom;
- failure to obtain industry partner and other third party consents and approvals, as and when required;
- stock market volatility and market valuations;
- competition for, among other things, capital, acquisition of reserves, undeveloped land and skilled personnel;
- the availability of capital on acceptable terms or at all;
- failure to realize the anticipated benefits of acquisitions and dispositions; and
- the other factors considered under "*Risk Factors*" below.

Statements relating to "reserves" are deemed to be forward-looking statements or information, as they involve the implied assessment, based on certain estimates and assumptions, that the resources and reserves described can be profitable in the future. There are numerous uncertainties inherent in estimating quantities of proved reserves, including many factors beyond the control of the Corporation. The reserve data included herein represents estimates only. In general, estimates of economically recoverable oil and gas reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary considerably from actual results. All such estimates are to some degree speculative and classifications of reserves are only attempts to define the degree of speculation involved. For those reasons, estimates of the economically recoverable oil and gas reserves attributable to any particular group of properties and classification of such reserves based on risk of recovery and estimates of future net revenues expected therefrom, prepared by different engineers or by the same engineers at different times, may vary substantially. The actual production, revenues, taxes and development and operating expenditures of the Corporation with respect to these reserves will vary from such estimates, and such variances could be material.

Spartan has included the above summary of assumptions and risks related to forward-looking information provided herein in order to provide investors with a more complete perspective on the Corporation's current and future operations and such information may not be appropriate for other purposes.

Readers are cautioned that the foregoing lists of factors are not exhaustive. The forward-looking statements contained herein, and the documents incorporated by reference herein, are expressly qualified by this

cautionary statement. Readers should also carefully consider the matters discussed under the heading "*Risk Factors*" below.

The forward-looking statements or information contained herein are made as of the date hereof and the Corporation undertakes no obligation to update or revise any forward looking statements, whether as a result of new information, future events or otherwise, unless required by applicable securities laws.

Caution Respecting BOE

In this Annual Information Form, the abbreviation BOE means a barrel of oil equivalent on the basis of 1 BOE to 6 Mcf of natural gas when converting natural gas to BOEs. **BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf to 1 BOE 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 of oil compared to natural gas based on currently prevailing prices is significantly different than the energy equivalency conversion ratio of 6 Mcf to 1 BOE, utilizing a conversion ratio of 6 Mcf to 1 BOE may be misleading as an indication of value.**

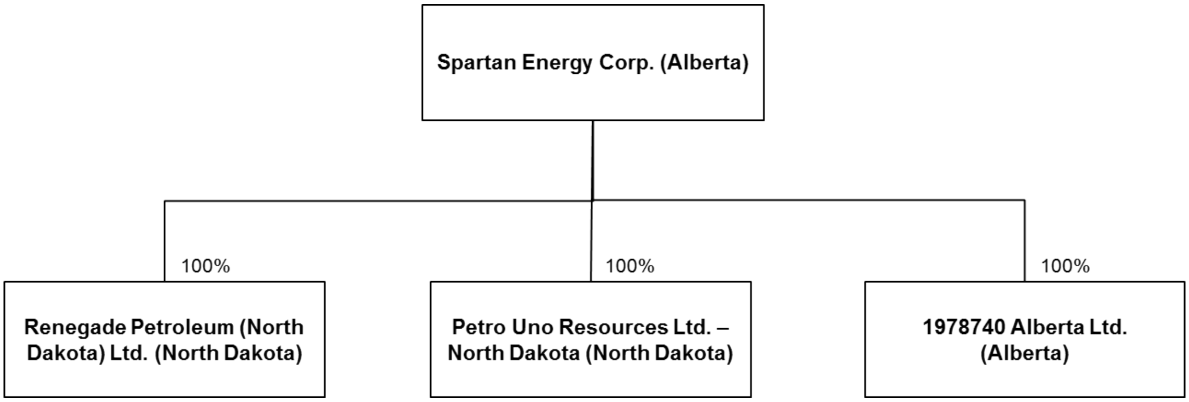
THE CORPORATION

The Corporation was incorporated pursuant to the provisions of the ABCA on December 12, 1988 as "394537 Alberta Ltd.". The Corporation changed its name to "Petro-Reef Resources Ltd." on February 23, 1989. On January 1, 2000, the Corporation amalgamated with twenty private Alberta numbered companies to form "Petro-Reef Resources Ltd.". The Corporation changed its name to "Alexander Energy Ltd." on September 9, 2012, and to "Spartan Energy Corp." on February 28, 2014. On March 31, 2014, Spartan completed the Arrangement with Renegade which included the amalgamation of Spartan and Renegade to form "Spartan Energy Corp.". On June 23, 2016, Spartan amalgamated with Wyatt to form "Spartan Energy Corp.".

On February 28, 2014, the Corporation filed articles of amendment to effect a share consolidation on the basis of one post-consolidation Common Share for every four pre-consolidation Common Shares, as approved at the special meeting of Shareholders held on February 18, 2014. On June 20, 2017, the Corporation filed articles of amendment to effect the Consolidation, on the basis of one post-Consolidation Common Share for every three pre-Consolidation Common Shares, as approved at the annual general and special meeting of Shareholders held on June 20, 2017.

Spartan's head office is located at Suite 3200, 500 Centre Street SW, Calgary, Alberta, T2G 1A6 and the registered office is located at Suite 4000, 421 – 7th Avenue, S.W., Calgary, Alberta, T2P 4K9.

The following diagram describes the inter-corporate relationships among the Corporation and its subsidiaries as at the date hereof:



As of the date hereof, the Corporation is a reporting issuer in British Columbia, Alberta, Saskatchewan, Manitoba, Ontario, New Brunswick and Nova Scotia. The Common Shares have been listed on the TSX under the trading symbol "SPE" since July 9, 2014. Previously, the Common Shares were listed on the TSXV.

GENERAL DEVELOPMENT OF THE BUSINESS

Three Year History

Financial Year Ended December 31, 2015

On December 22, 2015, Spartan closed a non-brokered private placement of 735,294 Common Shares issued on a "flow-through" basis pursuant to the Tax Act for gross proceeds of approximately $2.0 million.

During the financial year ended December 31, 2015, Spartan averaged production of 8,866 BOE/D, comprised of 95% oil and liquids. Spartan drilled 66 (56.5 net) wells over the course of the year and brought 59 (50.5 net) wells on production.

Financial Year Ended December 31, 2016

On March 16, 2016, Spartan closed a bought-deal financing of 39,938,375 Common Shares, including the exercise in full of the over-allotment option of 4,668,375 Common Shares, at a price of $2.41 per Common Share for gross proceeds of approximately $96.3 million.

On May 19, 2016, Spartan entered into an agreement with Wyatt whereby the Corporation agreed to acquire all of the issued and outstanding shares of Wyatt for total consideration of approximately $78.5 million, comprised of approximately 11.4 million Common Shares and the assumption of approximately $43.6 million of net debt. Pursuant to the acquisition, the Corporation acquired approximately 1,330 BOE/D of production (76% oil and liquids) in the Corporation's core southeast Saskatchewan operating area, including ownership of or access to strategic infrastructure to accommodate future growth. The Wyatt acquisition was completed on June 23, 2016.

On May 30, 2016, Spartan completed the acquisition of assets in the Winmore area of southeast Saskatchewan for consideration of approximately $9.4 million, comprised of approximately 2.3 million Common Shares and cash in the amount of $2.1 million. These assets consist of approximately 150 Bbls/d of light oil production and 16.6 net sections of land.

On June 30, 2016, Spartan completed the acquisition of assets in the Corning-Manor area of southeast Saskatchewan for cash consideration of approximately $62.0 million. These assets consist of approximately 1,500 BOE/D of low decline production (99% oil and liquids) and include all required production infrastructure, 1,141 km^2 of proprietary 3D seismic and 547km of proprietary 2D seismic.

On August 3, 2016, Spartan completed the acquisition of approximately 450 BOE/D (93% oil and liquids) of production in southeast Saskatchewan for cash consideration of approximately $23.4 million. The acquired assets include approximately 21.4 net sections of land complementary to Spartan's existing acreage in the Pinto and Alameda areas of southeast Saskatchewan which are prospective for drilling open-hole and fracture stimulated wells in the Midale formation.

On August 24, 2016, Spartan closed a bought-deal financing of 25,415,000 Common Shares, including the exercise in full of the over-allotment option of 3,315,000 Common Shares, at a price of $3.18 per Common Share for gross proceeds of approximately $80.8 million.

On November 17, 2016, Spartan entered an agreement in respect of the acquisition of certain strategic oil and gas assets in southeast Saskatchewan from ARC Resources Ltd. (the "**ARC Assets**") for cash consideration of approximately $691.5 million, after closing adjustments (the "**ARC Acquisition**"). The ARC Acquisition was completed on December 8, 2016 with an effective date of October 1, 2016.

The ARC Assets included approximately 7,500 BOE/D of production (98% oil and liquids) and an average working interest of approximately 87% in 35,007 gross (30,595 net) acres of undeveloped land (as at August 31, 2016). The properties included approximately 2,030 gross (1,624 net) producing oil wells and 749 gross (599 net) non-producing oil wells as at November 17, 2016. Major facilities include 30 light oil batteries, a 99% working interest in the Lougheed sour gas plant and an extensive network of field gathering infrastructure, as well as a working interest ownership in the Weyburn Unit and Midale Unit, two CO_2 enhanced recovery projects located in southeast Saskatchewan. The ARC Assets include an operated land position consisting of approximately 132,000 (98,000 net) acres of land.

On December 7, 2016, Spartan closed a private placement financing of 85,000,000 subscription receipts ("**Subscription Receipts**"), at a price of $3.00 per Subscription Receipt, for gross proceeds of approximately $255.0 million.

On December 8, 2016, Spartan closed a bought-deal financing of 95,852,500 Subscription Receipts, including the exercise in full of the over-allotment option of 12,502,500 Subscription Receipts, at a price of $3.00 per Subscription Receipt, for gross proceeds of approximately $287.6 million. In accordance with the terms of the private placement financing and bought deal financing, each Subscription Receipt was exchanged for one Common Share for no additional consideration on December 8, 2016 upon completion of the ARC Acquisition. Net proceeds of the private placement and bought deal financings were used to settle a portion of the purchase price for the acquired ARC Assets.

Also on December 8, 2016, in connection with the ARC Acquisition, the Credit Facility was amended to increase the borrowing base to $350 million comprised of: (i) an extendible revolving syndicated term credit facility of $320 million; and (ii) an extendible revolving working capital credit facility of $30 million.

During the financial year ended December 31, 2016, Spartan averaged production of 11,748 BOE/D, comprised of 92% oil and liquids. Spartan drilled 62 (53.7 net) wells over the course of the year and brought 69 (59.6 net) wells on production.

Financial Year Ended December 31, 2017

On March 23, 2017, Spartan completed the acquisition of approximately 30 BOE/D and 13.2 net sections of land prospective for Ratcliffe and Torquay drilling in the Oungre area for consideration of $6.5 million.

On June 20, 2017, the Corporation filed articles of amendment to effect the Consolidation, on the basis of one post-Consolidation Common Share for every three pre-Consolidation Common Shares, as approved at the annual general and special meeting of Shareholders held on June 20, 2017. Trading of the Common Shares on a post-Consolidation basis on the TSX commenced on June 23, 2017.

On July 4, 2017, Spartan increased its working interest in the Oungre unit to 100% for consideration of $4.4 million, adding production and reserves while strategically facilitating the implementation of its Oungre waterflood project.

On August 24, 2017, Spartan commenced a normal course issuer bid to purchase, from time to time, up to 8,780,148 Common Shares on the open market through the facilities of the TSX and/or other Canadian exchanges. Any Common Shares that are purchased under the normal course issuer bid will be cancelled. Unless renewed, the normal course issuer bid will terminate on August 23, 2018.

On December 15, 2017, Spartan completed the acquisition of certain oil and gas assets in its core Winmore area of southeast Saskatchewan for consideration of approximately $22.7 million, comprised of approximately 1.1 million Common Shares and cash in the amount of $15.4 million. The acquisition added approximately 250 BOE/D of low decline production and 45 net open-hole drilling locations.

During the financial year ended December 31, 2017, Spartan averaged production of 22,200 BOE/D, comprised of 92% oil and liquids. Spartan drilled 141 (117.0 net) wells over the course of the year and brought 139 (115.5 net) wells on production.

NARRATIVE DESCRIPTION OF THE BUSINESS

General

Business Objectives and Strategy

Spartan is predominantly focused on light and medium oil opportunities in Saskatchewan, growing through development drilling and the acquisition of long-life oil and gas assets. Spartan's extensive opportunity base and current oil weighted production base (92% oil and liquids) together with a well-capitalized corporate structure will allow for the exploitation of Spartan's current drilling inventory and expansion of Spartan's opportunity suite through internally generated prospects and strategic oil acquisitions. See "*Statement of Reserves Data and Other Oil and Gas Information*".

As part of its continued per share growth strategy, Spartan intends to strategically investigate and search out oil properties that will result in meaningful reserve and production additions and will deploy capital to higher-quality, longer-life reservoirs in proven growth areas that offer existing infrastructure, low cost oil drilling opportunities, year round access and operational control. Spartan's existing core operating properties in Saskatchewan are intended to be developed and expanded through a detailed technical analysis of information, including reservoir characteristics, original crude oil and natural gas in place, recovery factors and the application of exploitation drilling and enhanced recovery techniques, such as water flood schemes, multi-well fracturing programs and infill drilling programs.

In each of Spartan's core areas, Spartan's growth strategy is to:

1. acquire a land position or drilling opportunities to earn significant land positions;

2. build an inventory of low to medium risk drilling prospects drillable over a two to five year period;
3. efficiently control costs through facility ownership and operation of wells, where possible;
4. seek out opportunities where current leaseholders have time or resource constraints; and
5. manage risk through the geological and technical expertise Spartan has in each of these geographic areas.

To execute the business strategy, Spartan requires: (i) access to land and additional opportunities; (ii) appropriate commercial terms; (iii) access to services and goods for operations; (iv) acquisition and operational success; and (v) timely financing for all those activities.

Specialized Skill and Knowledge

It is the belief of management of Spartan that Spartan's officers and employees, who have significant technical and operational oil and gas experience, hold the necessary skill sets to successfully execute Spartan's business strategy in order to achieve its corporate objectives. In a relatively short period of time, Spartan's officers and employees have demonstrated the ability to profitably grow and expand Spartan's base of operations.

Spartan's geographically focused business expansion has positioned it to succeed in currently prevailing industry conditions. Since commencing active oil and gas operations, management of Spartan has established "critical mass", which includes a production base providing for a solid growth platform and a balanced production and prospect risk profile necessary to become a successful full-cycle exploration and development company. Spartan's inventory of drilling prospects generated internally as well as through acquisitions, combined with management's ability to execute strategic corporate and property acquisitions, is expected to continue to support and expand its existing asset base.

Personnel

As at December 31, 2017, Spartan had 65 full-time employees.

Industry Conditions

Legislation and Regulation

The oil and natural gas industry is subject to extensive controls and regulations governing its operations (including land tenure, exploration, development, production, refining, transportation and marketing) imposed by legislation enacted by various levels of government and with respect to pricing and taxation of oil and natural gas by agreements among the governments of Canada, Saskatchewan, Alberta and Manitoba all of which should be carefully considered by investors in the oil and gas industry. It is not expected that any of these controls or regulations will affect the operations of the Corporation in a manner materially different than they would affect other oil and gas companies of similar size. All current legislation is a matter of public record and the Corporation is unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the more significant aspects of the legislation, regulations and agreements governing the oil and gas industry.

Pricing and Marketing in Canada

Crude Oil

Producers of crude oil are entitled to negotiate sales contracts directly with crude oil purchasers, which results in the market determining the price of crude oil. Worldwide supply and demand factors primarily determine crude oil prices; however, regional market and transportation issues also influence prices. The specific price depends, in part, on crude oil quality, prices of competing fuels, distance to market, availability of transportation, value of refined products, supply/demand balance and contractual terms of sale.

Natural Gas

The price of natural gas sold in intra-provincial, interprovincial and international trade is determined by negotiation between buyers and sellers. The price received by a natural gas producer depends, in part, on the price of competing natural gas supplies and other fuels, natural gas quality, distance to market, availability of transportation, length of contract term, weather conditions, supply/demand balance and other contractual terms. Spot and future prices can also be influenced by supply and demand fundamentals on various trading platforms.

Natural Gas Liquids

The price of condensate and other NGLs sold in intra-provincial, interprovincial and international trade is determined by negotiation between buyers and sellers. Such price depends, in part, on the quality of the NGLs, price of competing chemical stock, distance to market, access to downstream transportation, length of contract term, supply/demand balance and other contractual terms.

Exports from Canada

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

Orders from the NEB provide a short-term alternative to export licences and may be issued more expediently, since they do not require a public hearing or approval from the cabinet of the Canadian federal government. Orders are issued pursuant to the Part VI Regulation for up to one or two years depending on the substance, with the exception of natural gas (other than NGLs) for which an order may be issued for up to twenty years for quantities not exceeding 30,000 m^3 per day.

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

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

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

Transportation Constraints and Market Access

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

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

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

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

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. Canada, the United States and Mexico began renegotiating the terms of NAFTA in mid-2017. The United States has also suggested that it might give notice of the termination of NAFTA if it is not satisfied with the outcome of the renegotiations. As of the date hereof, renegotiation discussions continue and the outcome of such negotiations remains unclear. As the United States remains Canada's largest trade partner and the largest international market for the export of crude oil, natural gas and NGLs from Canada, any changes to, or termination of, NAFTA could have an impact on Western Canada's crude oil and natural gas industry, including the Corporation's business.

Other Trade Agreements

Canada and ten other countries recently concluded discussions and agreed on the draft text of the Comprehensive and Progressive Agreement for Trans-Pacific Partnership ("**CPTPP**"), which is intended to allow for preferential market access among the countries that are parties to the CPTPP. The text of CPTPP has not been finalized or published and the agreement remains subject to ratification by the governments of each of the countries involved. While it is uncertain what effect CETA, CPTPP or any other trade agreements will have on the oil and gas industry in Canada, the lack of available infrastructure for the offshore export of oil and gas may limit the ability of Canadian oil and gas producers to benefit from such trade agreements.

Canada has also pursued a number of other international free trade agreements with countries around the world. Canada and the European Union recently agreed to the Comprehensive Economic and Trade Agreement ("**CETA**"), which provides for duty-free, quota-free market access for Canadian oil and gas products to the European Union. Although CETA remains subject to ratification by certain national legislatures in the European Union, provisional application of CETA commenced on September 21, 2017.

Extractive Sector Transparency Measures Act

The Extractive Sector Transparency Measures Act ("ESTMA"), a federal regime for the mandatory reporting of payments to government, came into force on June 1, 2015. ESTMA contains broad reporting obligations with respect to payments to governments and state owned entities, including employees and public office holders, made Canadian businesses involved in resource extraction. Under ESTMA, all payments made to payees (broadly defined to include any government or state owned enterprise) must be reported annually if the aggregate of all payments in a particular category to a particular payee exceeds $100,000 per financial year. The categories of payments include taxes, royalties, fees, bonuses, dividends and infrastructure improvement payments. Payments to aboriginal governments are exempt from reporting obligations until 2017. Failure to comply with the reporting obligations under ESTMA are punishable upon summary conviction with a fine of up to $250,000.

In addition, each day that passes prior to a non-compliant report being corrected forms a new offence, and therefore, a payment that goes unreported for a year could result in over $9,000,000 in total liability.

Competition

The oil and gas industry is competitive in all of its phases. Spartan 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. Spartan's competitors include resource companies which have much greater financial resources, staff and facilities than those of Spartan. Competitive factors in the distribution and marketing of oil and natural gas include price and methods and reliability of delivery. Spartan believes that its competitive position is similar to that of other oil and gas issuers of similar size and at a similar stage of development.

Provincial Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations that govern land tenure, royalties, production rates, environmental protection and other matters. The royalty regime is a significant factor in the profitability of crude oil, natural gas, natural gas liquids and sulphur production. Royalties payable on production from lands other than Crown lands are determined by negotiations between the mineral owner and the lessee, although production from such lands is also subject to certain provincial taxes and royalties. Operations not on Crown lands and subject to the provisions of specific agreements are also usually subject to royalties negotiated between the mineral owner and the lessee. These royalties are not eligible for incentive programs sponsored by various governments as discussed below. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the 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 from time to time carved out of the working interest owner's interest through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests or net carried interests.

From time to time the governments of the western Canadian provinces have established incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays and tax credits for the purpose of encouraging oil and natural gas exploration or enhanced recovery projects. The programs are designed to encourage exploration and development activity. In addition, such programs may be introduced to encourage producers to undertake initiatives using new technologies that may enhance or improve recovery of oil, natural gas and NGLs.

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

Saskatchewan

In Saskatchewan, the amount payable as a Crown royalty in respect of crude or a freehold production tax in respect of oil depends on the vintage of the oil, the type of the oil, the quantity of oil produced in a month and the price of the oil produced and specified adjustment factors determined monthly by the provincial government.

For both Crown royalty and freehold production tax purposes, conventional oil is categorized by oil type as either "heavy oil", "southwest designated oil" or "non-heavy oil other than southwest designated oil". The conventional royalty and production tax classifications as either "fourth tier oil", "third tier oil", "new oil" or "old oil" depending on the finished drilling date of a well and are applied to each of the three crude oil types slightly differently.

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

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

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

The amount payable as a Crown royalty or a freehold production tax in respect of natural gas production is determined by a sliding scale based on the monthly provincial average gas price published by the Saskatchewan government (effective February 1, 2012), the quantity produced in a given month, the type of natural gas, and the classification of the natural gas. Like conventional oil, natural gas may be classified as "non-associated gas" (gas produced from gas wells) or "associated gas" (gas produced from oil wells) and royalty rates are determined according to the finished drilling date of the respective well. Non-associated gas is classified as new gas (having a finished drilling date before February 9, 1998 with a first production date on or after October 1, 1976), third tier gas (having a finished drilling date on or after February 9, 1998 and before October 1, 2002), fourth tier gas (having a finished drilling date on or after October 1, 2002) and old gas (not classified as either third tier, fourth tier or new gas). A similar classification is used for associated gas except that the classification of old gas is not used, the definition of fourth tier gas also includes production from oil wells with a finished drilling date prior to

October 1, 2002, where the individual oil well has a gas-oil production ratio in any month of at least 3,500 m^3 of gas for every m^3 of oil, and new gas is defined as oil produced from a well with a finished drilling date before February 9, 1998 that received special approval, prior to October 1, 2002, to produce oil and gas concurrently without gas-oil ratio penalties.

On December 9, 2010, the Government of Saskatchewan enacted the Freehold Oil and Gas Production Tax Act, 2010 with the intention to facilitate the efficient payment of freehold production taxes by industry. Two new regulations with respect to this legislation are: (i) The Freehold Oil and Gas Production Tax Regulations, 2012 which sets out the terms and conditions under which the taxes are calculated and paid; and (ii) The Recovered Crude Oil Tax Regulations, 2012 which sets out the terms and conditions under which taxes on recovered crude oil that was delivered from a crude oil recovery facility on or after March 1, 2012 are to be calculated and paid. Base royalty rates are 5 percent for all fourth tier gas, 15 percent for third tier or new gas, and 20 percent for old gas. Where average well-head prices are above base prices, marginal royalty rates are applied to the proportion of production that is above the base gas price. Marginal royalty rates are 30 percent for all fourth tier gas, 35 percent for third tier and new gas, and 45 percent for old gas. The current regulatory scheme provides for certain differences with respect to the administration of fourth tier gas which is associated gas.

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

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

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

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

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

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

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

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

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

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

Effective April 1, 2014, the Saskatchewan Ministry of the Economy streamlined fees related to licenses and applications in the oil and gas sector by eliminating 10 different licensing fees, which resulted in an aggregate of 20,000 fee transactions per year, and replacing them with a single annual levy based on a company’s production and number of wells. While the fees have been streamlined, approvals to conduct the relevant activities are still required. These changes to the fee structure are part of ongoing work by the Government of Saskatchewan to streamline the licensing, regulation and monitoring processes in the oil and gas sector.

Alberta

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

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

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

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

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

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

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

Manitoba

In Manitoba, the royalty amount payable on oil produced from Crown lands depends on the classification of the oil produced as "old oil" (produced from a well drilled prior to April 1, 1974 that does not qualify as new oil or third tier oil), "new oil" (oil that is not third tier oil and is produced from a well drilled on or after April 1, 1974 and prior to April 1, 1999, from an abandoned well re-entered during that period, from an old oil well as a result of an enhanced recovery project implemented during that period, or from a horizontal well), "third tier oil" (oil produced from a vertical well drilled after April 1, 1999, an abandoned well re-entered after that date, an inactive vertical well activated after that date, a marginal well that has undergone a major workover, or from an old oil well or a new oil well as a result of an enhanced recovery project implemented after that date), or "holiday oil" (oil that is exempt from any royalty or tax payable). Royalty rates are calculated on a sliding scale and based on the monthly oil production from a spacing unit, or oil production allocated to a unit tract under a unit agreement or unit order from the Minister. For horizontal wells, the royalty on oil produced from Crown lands is calculated based on the amount of oil production allocated to a spacing unit in accordance with the applicable regulations.

Royalties payable on natural gas production from Crown lands are equal to 12.5% of the volume of natural gas sold, calculated for each production month.

Producers of oil and natural gas from freehold lands in Manitoba are required to pay monthly freehold production taxes. The freehold production tax payable on oil is calculated on a sliding scale based on the monthly production volume and the classification of oil as old oil, new oil, third tier oil and holiday oil. Producers of natural gas from freehold lands in Manitoba are required to pay a monthly freehold production tax equal to 1.2% of the volume sold, calculated per production month. There is no freehold production tax payable on gas consumed as lease fuel.

The Government of Manitoba maintains a Drilling Incentive Program (the "**Program**") with the intent of promoting investment in the sustainable development of petroleum resources. The Program provides the licensee of newly drilled wells, or qualifying wells where a major workover has been completed, with a holiday oil volume ("**HOV**") pursuant to which no Crown royalties or freehold production taxes are payable until the HOV has been produced. Under the Program, wells drilled for purposes of injection (or wells converted to injection prior to producing predetermined volumes of oil) in an approved enhanced oil recovery project earn a one-year holiday for portions of the project area. On December 20, 2013, Manitoba announced that the Program had been revised and extended for the period from January 1, 2014 to December 31, 2018.

The *Vertical Well Incentive* provides licensees of a newly drilled, vertical development or exploratory well drilled less than 1.6 km from the nearest well cased for production from the same or a deeper zone, with a HOV of 500 m^3.

The *Exploration and Deep Well Incentive* provides licensees of a newly drilled exploratory well or deep development well with a HOV as follows: (i) non-deep exploratory well drilled more than 1.6 km from a well cased for production from the same or a deeper zone earns a HOV of 4,000 m^3; (ii) deep exploratory well drilled below the Birdbear Formation earns a HOV of 8,000 m^3, and (iii) deep development well completed for production in the Birdbear or deeper formation earns a HOV of 8,000 m^3.

The *Horizontal Well Incentive* provides licensees of horizontal wells drilled prior to January 1, 2018 with a HOV of 8,000 m^3.

The *Marginal Well Major Workover Incentive* provides licensees of marginal wells where a major workover is completed prior to January 1, 2018 with a HOV of 500 m^3, with a marginal oil well defined as an abandoned well or a well that was either not operated over the previous 12 months or produced oil at an average rate of less than 3 m^3 per operating day.

The *Pressure Maintenance Project Incentive* provides licensees with a one year exemption from the payment of Crown royalties or freehold production taxes on production allocated to a unit tract in which a well is drilled or converted to injection of water or another substance in an approved new or modified pressure maintenance project. If a well is placed on injection before it has produced its HOV and within 5 years of the finished drilling date of the well, the exemption period is extended to 18 months.

The *Solution Gas Conservation Incentive* provides licensees with an exemption on Crown royalties and production taxes payable on gas captured from new solution gas conservation projects initiated and approved by the Direction after December 31, 2013. The exemption will apply from the project implementation date to December 31, 2018.

Under the Program, HOV accounts have been phased out as of January 1, 2015. Prior to that date, companies were able to assign a one-time maximum of 2,000 m^3 of HOV from their HOV account to vertical or horizontal wells drilled between January 1, 2014 and December 31, 2014. Effective January 1, 2014, companies were no longer able to assign HOV from a well to their HOV account or transfer HOV to another company.

The Program also implements a new minimum crown royalty rate of 3.0% and a minimum production tax rate of 1.0% payable during producing of HOV for wells drilled after December 31, 2013 and prior to January 1, 2019. The maximum Crown royalty and production tax rates apply during the production of HOV earned from the drilling of new wells and wells which have earned a marginal well major workover incentive during the period January 1, 2014 to December 31, 2018. The royalty payable is the lesser of the amount the well would have paid if a well was not producing holiday volume compared to the corresponding rates of 3% for a royalty or 1% for a freehold production tax.

Climate Change Regulation

Federal

Canada is a signatory to the United Nations Framework Convention on Climate Change (the "**UNFCCC**"), which was entered into in order work towards stabilizing atmospheric concentrations of greenhouse gas ("**GHG**") emissions at a level to prevent "dangerous anthropogenic interference with the climate system". The UNFCCC came into force on March 21, 1994. Subsequent international negotiations led to the Kyoto Protocol, an international treaty which extends the UNFCCC and commits its signatories to reduce GHG emissions. The Kyoto Protocol was adopted in December 1997 and came into force on February 16, 2005. Canada withdrew from the Kyoto Protocol effective December 2012. On December 12, 2015, the UNFCCC adopted the Paris Agreement, which Canada ratified on October 5, 2016. Under the Paris Agreement, countries have also committed to an ambitious goal of holding the increase in global average temperature to well below 2°C above pre-industrial levels, while they pursue efforts to limit the temperature increase to 1.5°C above pre-industrial levels. In 2018, members of the Paris Agreement launched the Talanoa dialogue in order to assess the members' collective efforts and progress with respect to the long term goal to peak global GHG emissions, and subsequently achieve net zero emissions.

In May 2015, Canada submitted its Intended Nationally Determined Contribution ("**INDC**") to the UNFCCC Secretariat, pledging a 30% reduction from 2005 levels – approximately 523 Mt – by 2030. In addition, provincial/territorial and federal leaders met and agreed that they would work together to build a national climate change plan. At a follow-up meeting of the First Ministers and Prime Minister on March 3, 2016, the parties agreed under the Vancouver Declaration on Clean Growth and Climate Change to launch a process to develop the Pan-Canadian Framework on Clean Growth and Climate Change (the "**Framework**"), which was released on December 9, 2016 at the First Ministers meeting. Saskatchewan was the only province that decided not to adopt the Framework.

Prior to the release of the Framework, the federal government announced in October 2016 that it will set a minimum price on carbon starting at $10 per tonne of CO_2e in 2018, which will increase by $10 per year until it reaches $50 per tonne of CO_2e by 2022. This approach will be reviewed in 2022 to confirm the path forward, including continued increases in stringency. Under the federal plan, each province and territory will be required to implement carbon pricing in its jurisdiction by 2018, whether in the form of a carbon tax or a cap-and-trade system. If the carbon price in a jurisdiction does not meet the federal minimum price, the federal government will step in and impose a carbon price that makes up the difference and return the revenue to the province or territory. In addition, provincial and territorial goals for reducing emissions must be at least as stringent as federal targets. Currently, Canada's four biggest provinces representing more than 80% of Canada's population (Ontario, Québec, Alberta and British Columbia) have carbon pricing in place that meets the federal benchmark.

In May 2017, Environment and Climate Change Canada ("**ECCC**") released its *Technical Paper on the Federal Carbon Pricing Backstop*, which was followed by the *Guidance on the Pan-Canadian Carbon Pollution Pricing Benchmark* in August 2017. In December 2017, *Supplemental Benchmark Guidance* was issued and federal Environment Minister Catherine McKenna and Finance Minister Bill Morneau announced a deadline of September 1, 2018 for each province to outline how it is implementing a carbon pricing system that meets the federal standard (the federal government has requested that provinces and territories that choose the federal backstop, in whole or in part, confirm this by March 30, 2018). The federal government will then determine whether the planned systems are on track to meet the standard, or whether the federal approach should be applied in that jurisdiction. On January 15, 2018, ECCC released draft legislative proposals for public comment relating to the proposed *Greenhouse Gas Pollution Pricing Act* and the proposed regulatory framework for the output-based pricing system (which is designed to minimize competitiveness risks for emissions-intensive, trade-exposed industrial facilities). The comment periods for the federal carbon pricing backstop legislation and the regulatory framework end on February 12, 2018 and April 9, 2018, respectively.

On May 27, 2017, the federal government published draft regulations to reduce emissions of methane from the crude oil and natural gas sector. The proposed regulations aim to reduce unintentional leaks and intentional venting of methane, as well as ensuring that crude oil and natural gas operations use low-emission equipment and processes, by introducing new control measures. Among other things, the proposed regulations limit how much methane upstream oil and gas facilities are permitted to vent. These facilities would need to capture the gas and either re-use it, re-inject it, send it to a sales pipeline, or route it to a flare. In addition, in provinces other than Alberta and British Columbia (which already regulate such activities), well completions by hydraulic fracturing would be required to conserve or destroy gas instead of venting. The federal government anticipates that these actions will reduce annual GHG emissions by about 20 megatonnes by 2030.

In March 2016, a Joint Statement on Climate, Energy, and Arctic Leadership was issued. This joint statement sets out specific commitments on energy development, environmental protection, and Arctic leadership. In particular, Canada and the US have made commitments to reduce methane emissions by 40-45% below 2012 levels by 2025 from the oil and gas sector, finalize and implement the second phase of an aligned GHG emission standard for post-2018 model year on-road heavy duty vehicles, phase out fossil fuel subsidies, accelerate clean energy development and foster sustainable energy development.

In December 2017, ECCC published its updated requirements and step-by-step reporting instructions in advance of the 2017 reporting period under the federal *Greenhouse Gas Reporting Program* ("**GHGRP**"). The Notice with respect to reporting of greenhouse gases for 2017, which was published on December 30, 2017 in Part I of the *Canada Gazette,* outlines the 2017 reporting requirements for GHG-emitting facilities. In December 2017, ECCC published its updated requirements and step-by-step reporting instructions in advance of the 2017 reporting period under the GHGRP. Stakeholders should note that for the 2017 reporting year under the GHGRP, the reporting threshold has been lowered from 50,000 tonnes to 10,000 tonnes of CO2e. All facilities that emitted the equivalent of 10,000 tonnes of CO2e in 2017 will be required to submit a report by June 1, 2018.

In November 2016, the federal government announced that it would commence development of a performance-based clean fuel standard ("**CFS**") that would incent the use of a broad range of low carbon fuels, energy sources and technologies. The objective of the CFS is to achieve 30 Mt of annual reductions in GHG emissions by 2030, as part of efforts to achieve Canada's commitments under the Paris Agreement. On December 13, 2017, ECCC published a regulatory framework on the CFS, which outlines the key design elements for the CFS regulation, including its scope, regulated parties, carbon intensity approach, timing, and potential compliance options such as credit trading. Draft CFS regulations are expected to be published in late 2018.

Spartan will continue to monitor the policies of the Government of Canada and any resulting legislation with respect to GHG emissions. The US Environmental Protection Agency ("**EPA**") is proceeding to regulate GHGs under the *Clean Air Act*. This EPA action is subject to legal and political challenges, the outcome of which cannot be predicted. The ultimate form of Canadian regulation is anticipated to be strongly influenced by the regulatory decisions made within the United States. Various states have enacted or are evaluating low carbon fuel standards, which may affect access to market for crude oils with higher emissions intensity.

Saskatchewan

In October 2016, Saskatchewan released its Climate Change White Paper, which outlined the principles of the province's approach to climate change, including a focus on both mitigation and adaptation responses to climate change. Following the release of the White Paper, the government worked on developing its comprehensive climate change strategy, which was released in December 2017: Prairie Resilience: A Made-in-Saskatchewan Climate Change Strategy (the "**Strategy**"). The Strategy focuses on the principles of readiness and climate resilience, curbing GHG emissions, and preparing for changing conditions such as extreme weather, drought or wildfire. Saskatchewan has decided not to sign on to the Pan-Canadian Framework on Clean Growth and Climate Change or to adopt a carbon pricing mechanism, meaning that it will be out of compliance with federal requirements. The Strategy proposes actions in key areas, including (i) natural systems; (ii) physical infrastructure; (iii) economic sustainability; (iv) community preparedness; and (v) measuring, monitoring and reporting. Although no specific emission reduction targets are set out in the Strategy, the Saskatchewan government has indicated that it will support Canada's efforts to meet national commitments under the Paris Agreement. Prior to the release of the Strategy, Saskatchewan relied on the GoGreen Saskatchewan initiative to encourage the reduction of GHG emissions and to educate the public about climate change. Between 2008 and 2015, the Saskatchewan government estimates that it invested $60 million in GoGreen funding through public/private partnerships.

Saskatchewan has also identified technology as a key driver of emission reductions, including carbon capture use and storage as well as renewable energy. In 2015, SaskPower set a target of doubling its percentage of electricity capacity from renewable energy sources, i.e. to have 50% of the province's power sourced from renewables by 2030.

As part of the Strategy, Saskatchewan will develop annual GHG reporting regulations for facilities that emit more than 25,000 tonnes of CO_2e annually (with a voluntary opt-in for emitters over 10,000 tonnes of CO_2e annually).

Alberta

On July 1, 2007, the *Specified Gas Emitters Regulation* ("**SGER**") came into force under Alberta's *Climate Change and Emissions Management Amendment Act* requiring Alberta facilities which emit more than 100,000 tonnes of GHGs annually ("**Regulated Emitters**") to reduce their GHG emissions intensity by 12% (from average 2003-2005 levels). 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.

Alberta's Climate Leadership Plan was introduced in November 2015 with the following policy objectives: (i) putting a price on GHG emissions; (ii) phasing out coal-generated electricity by 2030; (iii) having 30% of electricity be generated from renewable sources by 2030; (iv) capping oil sands emissions to 100 Mt per year; and (v)reducing methane emissions by 45% by 2025.

Carbon pricing was identified under the Climate Leadership Plan as a key policy tool for reducing GHG emissions. On January 1, 2017, a carbon levy of $20 per tonne of CO_2e was implemented and applies to all heating and transportation fuels. The carbon levy increased to $30 per tonne on January 1, 2018.

On January 1, 2018, the *Carbon Competitiveness Incentive Regulation* ("**CCI Regulation**") replaced the *Specified Gas Emitters Regulation*. Under the CCI Regulation, facilities are allowed to emit a certain amount of GHG, free of charge from the carbon levy. This approach is designed to protect industries from competitiveness impacts that could shift production to other jurisdictions. The CCI Regulation applies to facilities that emitted 100,000 tonnes or more of GHG in 2003, or a subsequent year. A facility with less than 100,000 tonnes of GHG may be eligible to opt-in to the CCI Regulation if it competes against a facility regulated under the CCI or has more than 50,000 tonnes of annual emissions, high emissions-intensity and trade-exposure (by opting in, facilities become exempt from the application of the carbon levy for fuels whose emissions are included in their site reporting). Under the updated system, a facility will receive performance credits if its GHG emissions are less than the amount freely permitted. If its emissions are above the amount freely permitted, they will be required take one or more of the following actions to bring the facility into compliance:

- make improvements at their facility to reduce emissions intensity;
- use emission performance credits generated at facilities that achieve more than the required reductions;
- purchase Alberta-based carbon offset credits; or
- contribute to Alberta's Climate Change and Emissions Management Fund.

Emissions from the oil sands sector (which account for approximately one-quarter of Alberta's annual emissions) have been capped at 100 Mt per year. This cap has been legislated in the *Oil Sands Emissions Limit Act* (Bill 25), which was introduced in November 2016. The legislation contemplates certain exceptions in respect of cogeneration emissions, upgrading emissions, and potential discretionary exemptions by regulation (likely to accommodate new technological developments). Bill 25 came into force on December 14, 2016.

In January 2018, the Alberta government also announced that it is adopting ECCC's greenhouse gas reporting requirements for the 2017 reporting period, meaning that facilities emitting 10,000 tonnes of CO_2e or more must submit a specified gas report to Alberta Climate Change Office via ECCC's SWIM reporting system (the reporting threshold for previous years is 50,000 tonnes of CO_2e). Facilities must report their 2017 greenhouse gas emissions to ECCC's SWIM system by June 1, 2018.

Manitoba

In October 2017, Manitoba released its Made-in-Manitoba Climate and Green Plan (the "**Manitoba Plan**"), which proposes a fixed carbon price of $25 per tonne of CO_2e. Under the Manitoba Plan, an output-based pricing approach has been proposed for large emitters in order to minimize competitiveness and carbon leakage risks to industries that are emissions-intensive and trade-exposed. This system, to be introduced in 2019, would apply carbon pricing to that portion of a facility's emissions that exceed a designated emissions-intensity performance standard for that type of facility. A facility that emits less than what is allowed under the performance standard would receive a credit (which can be banked or traded) for each tonne of surplus CO_2e between the standard and the facility's actual emissions.

One of the design features of Manitoba's carbon price is that it will remain fixed at $25 per tonne. By implementing a $25 per tonne carbon price right away (rather than starting low and ramping up over time), the province will be able to drive additional emission reductions in the short-term by sending a strong price signal to incentivize greater efficiency or the switch to lower carbon alternatives. However, by maintaining the carbon price at $25, the policy will drive fewer emissions reductions in the long run than if it increased to $30 in 2020, $40 in 2021 and $50 in 2022, in line with the pricing plan under the federal Pan-Canadian Framework on Clean Growth and Climate Change. Manitoba has sought to justify its carbon pricing approach by introducing the concept of "cumulative emission reductions", which considers total emissions reductions from 2018 to 2022, rather than annual emission reductions. According to the Manitoba Plan, its carbon pricing approach will drive sufficient emission reductions without having to increase the carbon price beyond $25.

In January 2012, Manitoba introduced a tax on coal emissions through the *Emissions Tax on Coal Act*. All coal tax revenues are being redirected to the Manitoba Agriculture, Food and Rural Development's Biomass Energy Support Program in order to support the conversion to biomass energy. Manitoba has also banned the use of coal and petroleum coke for space heating and taxing petroleum coke used for non-space heating purposes (which was phased-in beginning January 1, 2014).

Land Tenure

Crude oil and natural gas located in the western provinces is owned predominantly by the respective provincial governments. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences and permits for varying terms from two years and on conditions set forth in provincial legislation including requirements to perform specific work or make payments. Oil and natural gas located in such provinces can also be privately owned 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.

The respective provincial governments predominantly own the rights to crude oil and natural gas located in the western provinces, with the exception of Manitoba where private ownership accounts for approximately 80 percent of the crude oil and natural gas rights in the southwestern portion of the province. 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 Saskatchewan has 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 license.

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 licenses. For leases and licenses issued subsequent to January 1, 2009, shallow rights reversion will be applied at the conclusion of the primary term of the lease or license. Holders of leases or licences that have been continued indefinitely prior to January 1, 2009 will receive a notice regarding the reversion of the shallow rights, which will be implemented three years from the date of the notice. In 2013, Alberta Energy placed an indefinite hold on serving shallow rights reversion notices for leases and licences that were granted prior to January 1, 2009. Alberta Energy stated that it will provide the industry with notice if, in the future, a decision is made to serve shallow rights reversion notices.

Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation, all of which is subject to governmental review and revision from time to time. Such legislation provides for restrictions and prohibitions on the release or emitting of various substances produced in association with certain oil and gas industry operations, such as sulphur dioxide and nitrous oxide. In addition, such legislation sets out the requirements for the satisfactory abandonment and reclamation of well and facility sites and provides form among other things, restrictions and prohibitions on spills, releases, discharges, or emissions of various substances produced in association with oil and gas operations, habitat protection and minimum setbacks of oil and gas activities from fresh water bodies. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage, and the imposition of material fines and penalties. Certain environmental protection legislation may subject Spartan to statutory strict liability in the event of an accidental spill or discharge from a licensed facility, meaning that fault need not be established by claimants affected by such a spill or discharge. Further, as Canadian environmental legislation evolves, the use of administrative penalties by the imposition of fines for the commission of environmental offences on an absolute liability basis has grown.

Environmental legislation is evolving in a manner that has and is expected to continue to result in stricter standards and enforcement, larger fines, liabilities and sanctions, and potentially increased capital expenditures and operating costs. To mitigate potential environmental liabilities, Spartan, in addition to implementing policies and procedures designed to prevent an accidental spill or discharge, maintains insurance at industry standards.

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* and the *Canadian Environmental Assessment Act*, provide the foundation for the federal government to protect the environment and cooperate with provinces to do the same.

On February 8, 2018, the Government of Canada introduced draft legislation to overhaul the existing environmental assessment process and replace the NEB with the Canadian Energy Regulator ("**CER**"). Pursuant to the draft legislation, the Impact Assessment Agency of Canada (the "**Agency**") would replace the Canadian Environmental Assessment Agency. Additional categories of projects may be included within new impact assessment process, such as largescale wind power facilities and in-situ oilsands facilities. The revamped approval process for applicable major developments will have specific legislated timelines at each stage of the formal impact assessment process. The Agency's process would focus on: (i) early engagement by proponents to engage the Agency and all stakeholders, such as the public and indigenous groups, prior to the formal impact assessment process; (ii) potentially increased public participation where the project undergoes a panel review; (iii) providing analysis of the potential impacts and effects of a project without making recommendations, to support a public-interest approach to decision-making, with cost-benefit determinations and approvals made by the Minister of Environment and Climate Change or the cabinet of the federal government; (iv) analyzing further specified factors for projects such as alternatives to the project and social and indigenous issues in addition to health, environmental and economic impacts; and (v) overseeing an expanded follow-up, monitoring and enforcement process with increased involvement of indigenous peoples and communities. Many of the CER's activities would be similar to the NEB, but with a different structure and the notable exception that the CER would no longer have primary responsibility in the consideration of the new major projects, instead focusing on the lifecycle regulation (e.g. overseeing construction, tolls and tariffs, operations and eventual winding down) of approved projects, while providing for expanded participation by communities and indigenous peoples. It is unclear when the new regulatory scheme will come into force or whether any amendments will be made prior to coming into force. Until then, the federal government's interim principles released on January 27, 2016 will continue to guide decision-making authorities for projects currently undergoing environmental assessment. The effects of the proposed regulatory scheme remains unclear.

On May 12, 2017, the federal government introduced the *Oil Tanker Moratorium Act* in Parliament. This legislation is aimed at providing coastal protection in northern British Columbia by prohibiting crude oil tankers carrying more than 12,500 metric tonnes of crude oil or persistent crude oil products from stopping, loading, or unloading crude oil in that area. Parliament is still considering the bill, which passed second reading on October 4, 2017. If implemented, the legislation may prevent the building of pipelines to, and export terminals located on, the portion of the British Columbia coast subject to the moratorium and, as a result, negatively affect the ability of producers to access global markets.

Alberta

Environmental legislation in the Province of Alberta is, for the most part, set out in the *Environmental Protection and Enhancement Act* (the "**EPEA**"), the *Water Act* and the *Oil and Gas Conservation Act* ("**ABOGCA**"). EPEA, the *Water Act* and the ABOGCA impose strict environmental standards with respect to releases of effluents and emissions, require stringent compliance, reporting and monitoring obligations, and impose significant penalties for non-compliance.

The regulatory landscape in Alberta has undergone a transformation from multiple regulatory bodies to a single regulator for upstream oil and gas, oil sands and coal development activity. On June 17, 2013, the Alberta Energy Regulator (the "**AER**") assumed the functions and responsibilities of the former Energy Resources Conservation Board, including those found under the ABOGCA. On November 30, 2013, the AER assumed the energy related functions and responsibilities of Alberta Environment and Parks ("**AEP**") in respect of the disposition and management of public lands under the *Public Lands Act.* On March 29, 2014, the AER assumed the energy related functions and responsibilities of AEP in the areas of environment and water under EPEA and the *Water Act,* respectively. 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 the transformation to a single regulator is the creation of 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.

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.

The *Alberta Land Stewardship Act* (the "**ALSA**") was proclaimed in force in Alberta on October 1, 2009, providing the legislative authority for the Government of Alberta to implement the policies contained in the ALUF. Regional plans established pursuant to the ALSA are deemed to be legislative instruments equivalent to regulations and are 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, licenses, 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 oilsands area, which contains approximately 82 percent of the province's oilsands resources and much of the Cold Lake oilsands 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.

The South Saskatchewan Regional Plan ("**SSRP**") was approved by the Government of Alberta on July 23, 2014 and became effective on September 1, 2014. The SSRP is the second regional plan developed under the ALUF and covers approximately 83,764 square kilometres and includes 44 percent of the province's 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, oil and gas companies must nonetheless minimize impacts of activities on the natural landscape, historic resources, wildlife, fish and vegetation when exploring, developing and extracting the resources. Any new petroleum and natural gas tenures sold in conservation areas, provincial parks, and recreational areas will prohibit surface access. Freehold mineral rights will not be subject to this restriction. With the implementation of the new Alberta regulatory structure under the AER, AEP will remain responsible for development and implementation of regional plans. However, the AER will take on some responsibility for implementing regional plans in respect of energy related activities.

Saskatchewan

The Corporation has operations in Saskatchewan and, as such, is also subject to the Saskatchewan *Environmental Management and Protection Act, 2002* (the "**EMPA**") and *Oil and Gas Conservation Act* (the "**SKOGCA**"). The EMPA and the SKOGCA regulate and control harmful or potentially harmful activities and substances, any release of such substances to the air, water, or land, and remediation obligations in Saskatchewan. Certain development activities in Saskatchewan, depending on the location and potential environmental impact, may require a screening or an environmental impact assessment under the provincial *Environmental Assessment Act*. With implementation anticipated shortly, Saskatchewan is currently working towards a new legal framework, the Saskatchewan Environmental Code, which aims to address specific activities and standards under current environmental legislation as well as introduce new regulations for the management of greenhouse gases.

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

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

Manitoba

The Corporation owns oil and natural gas properties and related assets in Manitoba and, as such, is subject to regulation under the *Oil and Gas Act* ("**MBOGA**") which incorporates provisions related to the environment from *The Environment Act*, *The Oil and Gas Production Tax Act*, and *The Surface Rights Act*. This legislation imposes obligations to protect, preserve and, where required, rehabilitate the environment and provides penalties in the event of non-compliance.

Compliance with Environmental Legislation

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 third parties and may require Spartan to incur costs to remedy any such discharge not covered by Spartan's insurance. Although Spartan maintains insurance to industry standards, which in part covers liabilities associated with discharges, it is not certain that such insurance will cover all possible environmental events, foreseeable or otherwise, or whether changing regulatory requirements or emerging jurisprudence may render such insurance of little benefit. Further, Spartan expects incremental future compliance costs in light of increasingly more complex environmental protection requirements, some of which may require the installation of emissions monitoring and measuring devices and the verification of emissions data.

Spartan believes it is in material compliance with environmental legislation at this time. Spartan is committed to meeting its responsibilities to protect the environment wherever it operates and will take such steps as required to ensure compliance with environmental legislation. No assurance can be given, however, that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise adversely affect the Corporation's financial condition, results of operations or prospects.

Spartan is obligated to abandon, retire and reclaim wells, well sites and facilities in compliance with applicable environmental laws and regulations. As of December 31, 2017, Spartan has recorded in its financial statements decommissioning liabilities of $286.5 million. The decommissioning liability is anticipated to be funded by future cash flow as required. No abandonment expenses were incurred in 2017.

Other than decommissioning liabilities, ordinary course operational expenditures necessary to ensure environmental compliance and the employment cost of health, safety and environmental personnel and programs. Spartan is not aware of any environmental protection requirement that will impact its capital expenditures, earnings or competitive position in a manner disproportionate to that of its peers in its areas of operation.

Liability Management Rating Programs

Alberta

In Alberta, the AER administers the Licensee Liability Rating Program (the "**AB LLR Program**") as part of the Liability Management Rating Assessment Process. The AB LLR Program is a liability management program governing most conventional upstream oil and gas wells, facilities and pipelines. The ABOGCA 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. 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 prevent the taxpayers of Alberta from incurring costs to suspend, abandon, remediate and reclaim wells, facilities or pipelines. In short, the AB LLR Program requires a licensee whose deemed liabilities exceed its deemed assets (and therefore the licensee has a resulting LLR of less than 1.0) to provide the AER with a security deposit. In certain circumstances, for example during the transfer of AER licenses between parties, the AER will require that the transferee must achieve an LLR of 2.0 or higher immediately following the proposed transfer of the applicable licenses. The ratio of deemed liabilities to deemed assets is assessed once each month and upon the submission of a license transfer application, and failure to post the required security deposit may result in the initiation of enforcement actions by the AER.

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 was affirmed by a majority at the Alberta Court of Appeal. In Redwater Energy Corporation (Re), 2016 ABQB 278 ("**Redwater**"), Chief Justice Wittman found that there was an operational conflict between the abandonment and reclamation provisions of the *Oil and Gas Conservation Act* (Alberta) 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. The decision is currently under appeal to the Supreme Court of Canada, with final decision expected in 2018.

The AER issued several bulletins in response to Redwater. 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. The AER's Directive 67 was amended and now requires extensive corporate governance and shareholder information, with a focus on any previous insolvency proceedings in order to acquire or transfer licenses needed to operate wells and facilities. The AER will consider and process all applications for licence eligibility under Directive 067: Applying for Approval to Hold EUB Licences as non-routine and may exercise its discretion to refuse an application or impose terms and conditions on a licensee eligibility approval if appropriate in the circumstances. 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. The AER may implement additional changes in response to the final Redwater 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. The objective is to bring all inactive noncompliant wells under the IWCP into compliance with the requirements of Directive 013 within five years. As of April 1, 2015, each licensee is required to bring 20% of its inactive wells into compliance every year, either by reactivating or 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. The IWCP completed its second year on March 31, 2017. Overall, the AER has announced that licensees brought 19% of non-compliant wells in the IWCP into compliance with AER requirements in the second year of the IWCP.

Saskatchewan

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

Manitoba

To date, the Government of Manitoba has not implemented a liability management rating program similar to those found in the other western provinces. However, operators of wells licensed in the province are required to post a performance deposit to ensure that the operation and abandonment of wells and the rehabilitation of sites occurs in accordance with the MBOGA and the Drilling and Production Regulations. In certain circumstances, a performance deposit may be refunded. The MBOGA also establishes the Abandonment Fund Reserve Account (the "**Abandonment Fund**"). The Abandonment Fund is a source of funds that may be used to operate or abandon a well when the licensee or permittee fails to comply with the MBOGA. The Abandonment Fund may also be used to rehabilitate the site of an abandoned well or facility or to address any adverse effect on property caused by a well or facility. Deposits into the Abandonment Fund are comprised of non-refundable levies charged when certain licences and permits are issued or transferred as well as annual levies for inactive wells and batteries.

Social or Environmental Policies

The health and safety of employees, contractors and the public, as well as the protection of the environment, is of utmost importance to Spartan. To this end, the Corporation has instituted a comprehensive environmental policy to which it and its employees and contractors are required to adhere. Spartan endeavours to conduct its operations in a manner that will minimize both adverse effects and consequences of emergency situations by:

- complying with government regulations and standards, particularly relating to the environment, health and safety;
- operating consistent with industry codes, practices and guidelines;
- ensuring prompt, effective response and repair to emergency situations and environmental incidents;
- providing training to employees and contractors to ensure compliance with corporate safety and environmental rules and procedures; and
- communicating openly with members of the public regarding its activities.

Spartan believes that all employees have a vital role in achieving excellence in environmental, health and safety performance, which is best achieved through careful planning and the support and active participation of everyone involved. To further ensure that the Corporation achieves excellence in health and safety performance, an emergency response plan and a corporate safety policy have been implemented. Furthermore, the Corporation aligns itself with the best industry practices to ensure positive results.

RISK FACTORS

Spartan's business consists of the exploration and production of crude oil and natural gas projects, with properties in Saskatchewan, Alberta and Manitoba. There are a number of inherent risks associated with the exploration and production of oil and gas reserves. Many of these risks are beyond the control of the Corporation. Investors should carefully consider the risk factors set out below and consider all other information contained herein and in the Corporation's other public filings before making an investment decision.

Commodity Price Volatility

Spartan's results of operations and financial condition are dependent on the prevailing prices of crude oil and natural gas. Crude oil and natural gas prices have fluctuated widely in the recent past and are subject to fluctuations in response to relatively minor changes in supply, demand, market uncertainty and other factors that are beyond Spartan's control. Crude oil and natural gas prices are impacted by a number of factors including, but not limited to: the global supply of and demand for crude oil and natural gas; global economic conditions; the actions of the Organization of Petroleum Exporting Countries ("**OPEC**"); government regulation; political stability; the ability to transport crude to markets; developments related to the market for liquefied natural gas; the availability and prices of alternate fuel sources; and weather conditions. In addition, significant growth in crude production volumes in western Canada and the northern United States has resulted in pressure on transportation and pipeline capacity, contributing to the widening of the light oil pricing differential between WTI and Cromer/WCS/Hardisty, resulting in fluctuations in the price of oil and natural gas. All of these factors are beyond Spartan's control and can result in a high degree of price volatility.

Fluctuations in currency exchange rates further compound this volatility when the commodity prices, which are generally set in U.S. dollars, are stated in Canadian dollars. Spartan's financial performance also depends on revenues from the sale of commodities which differ in quality and location from underlying commodity prices quoted on financial exchanges. Of particular importance are the price differentials between the Corporation's light/medium oil and heavy oil (in particular the light/heavy differential) and quoted market prices. Not only are these discounts influenced by regional supply and demand factors, they are also influenced by other factors such as transportation costs, capacity and interruptions; refining demand; the availability and cost of diluent used to blend and transport product; and the quality of the oil produced, all of which are beyond Spartan's control. See also "*Variations in Foreign Exchange Rates and Interest Rates*".

Fluctuations in the price of commodities and associated price differentials may impact the value of Spartan's assets, the Corporation's ability to maintain its business and to fund growth projects. Prolonged periods of commodity price depression and volatility may also negatively impact Spartan's ability to meet guidance targets and meet all of its financial obligations as they come due. Any substantial and extended decline in the price of oil and gas would have an adverse effect on the Corporation's carrying value of its reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on the Corporation's business, financial condition, results of operations, prospects and the level of expenditures for the development of oil and natural gas reserves, including delay or cancellation of existing or future drilling or development programs or curtailment in production.

Any material or sustained decline in prices could result in a reduction of the Corporation's net production revenue. The economics of producing from some wells may change as a result of lower prices, which could result in reduced production of oil or gas and a reduction in the volumes of the Corporation's reserves. Spartan might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in the Corporation's expected net production revenue and a reduction in its oil and gas acquisition, development and exploration activities.

Crude oil and natural gas prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and the demand of these commodities due to the current state of the world economies and OPEC actions. Volatile oil and gas prices make it difficult to estimate the value of producing properties for acquisition and often cause disruption in the market for oil and 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.

In addition, bank borrowings available to the Corporation may, in part, be determined by the Corporation's borrowing base. A sustained material decline in prices from historical average prices could reduce the

Corporation's borrowing base, therefore reducing the bank credit available to the Corporation which could require that a portion, or all, of the Corporation's bank debt be repaid.

Spartan conducts regular assessments of the carrying value of its assets in accordance with International Financial Reporting Standards. If crude oil and natural gas prices decline significantly and remain at low levels for an extended period of time, the carrying value of the Corporation's assets may be subject to impairment.

Capital Lending Markets

As a result of recent economic uncertainties in the oil and gas industry and, in particular, the lack of risk capital available to the oil and gas sector, the Corporation, along with other oil and gas entities, may have reduced access to bank debt and to equity. As future capital expenditures will be financed out of funds generated from operations, bank borrowings, if available, and possible issuances of debt or equity securities, the Corporation's ability to fund future capital expenditures is dependent on, among other factors, the overall state of lending and capital markets and investor and lender appetite for investments in the energy industry, generally, and the Corporation's securities in particular.

To the extent that external sources of capital become limited, unavailable or available only on onerous terms, the Corporation's ability to invest and to maintain existing assets may be impaired, and its assets, liabilities, business, financial condition and results of operations may be materially and adversely affected as a result.

Markets and Marketing

The marketability and price of crude oil and natural gas that may be acquired or discovered by the Corporation is and will continue to be affected by numerous factors beyond its control. Spartan's ability to market its crude oil and natural gas may depend upon its ability to acquire space on pipelines that deliver crude oil and natural gas to commercial markets. Spartan may also be affected by deliverability uncertainties related to the proximity of its reserves to pipelines and processing and storage facilities and operational problems affecting such pipelines and facilities as well as extensive government regulation relating to price, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and gas business.

Exploration, Development and Production Risks

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of the Corporation depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, any existing reserves the Corporation may have at any particular time, and the production therefrom will decline over time as such existing reserves are exploited. A future increase in the Corporation's reserves will depend not only on its ability to explore and develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. No assurance can be given that the Corporation will be able to continue to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participations are identified, management of the Corporation may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic. There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by the Corporation.

Future oil and natural gas exploration may involve unprofitable efforts, not only from dry wells, but also from wells that are productive but do not produce sufficient petroleum substances to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected 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, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely 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 hazards such as fire, explosion, blowouts, cratering, sour gas releases and spills, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or personal injury. In particular, the Corporation may explore for and produce sour natural gas in certain areas. An unintentional leak of sour natural gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability to the Corporation. In accordance with industry practice, the Corporation is not fully insured against all of these risks, nor are all such risks insurable. Although the Corporation maintains liability insurance in an amount that it considers consistent with industry practice, the nature of these risks is such that liabilities could exceed policy limits, in which event the Corporation could incur significant costs. Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Weakness in the Oil and Gas Industry

Recent market events and conditions, including global excess oil and natural gas supply, actions taken by 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 political and other actions resulting in uncertainty surrounding regulatory, tax, royalty changes and environmental regulation. In addition, the inability to get the necessary approvals to build pipelines, liquefied natural gas plants and other facilities to provide better access to markets for the oil and gas industry in Western Canada has led to additional downward price pressure on oil and gas produced in Western Canada and uncertainty and reduced confidence in the oil and gas industry in Western Canada. Lower commodity prices may also affect the volume and value of the Corporation's reserves, rendering certain reserves uneconomic. In addition, lower commodity prices have restricted, and may continue to restrict, the Corporation's cash flow resulting in a reduced capital expenditure budget. Consequently, the Corporation may not be able to replace its production with additional reserves and both the Corporation's production and reserves could be reduced on a year over year basis.

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 2016 presidential campaign a number of election promises were made and the new American administration has begun taking steps to implement certain of these promises. The administration has announced withdrawal of the United States from the Trans-Pacific Partnership and Congress has passed sweeping tax reform, which among other things, significantly reduces US corporate tax rates. This may affect competitiveness of other jurisdictions, including Canada. NAFTA is currently under renegotiation and the result is uncertain at this time. The administration has also taken action with respect to reduction of regulation which may also affect relative competitiveness of other jurisdictions. It is unclear exactly what other 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, 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. 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 Spartan.

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

A change in federal, provincial or municipal governments in Canada may have an impact on the directions taken by such governments on matters that may impact the oil and gas industry including the balance between economic development and environmental policy such as the potential impact of the recent change of government in British Columbia and announcements and actions by the government of British Columbia that may impact the completion of the Trans- Mountain Pipeline project and other infrastructure projects.

Credit Facility Risks

The Corporation currently has the Credit Facility and the amount authorized thereunder is dependent on the borrowing base determined by its lenders. The Corporation is required to comply with certain operating covenants under the Credit Facility which may, in certain cases, affect the availability, or price, of additional funding and in the event that the Corporation does not comply with these covenants, the Corporation's access to capital could be restricted or repayment could be required. Events beyond the Corporation's control may contribute to the failure of the Corporation to comply with such covenants. A failure to comply with covenants could result in default under the Credit Facility, which could result in the Corporation being required to repay amounts owing thereunder. Even if the Corporation is able to obtain new financing, it may not be on commercially reasonable terms or terms that are acceptable to the Corporation. If the Corporation is unable to repay amounts owing under the Credit Facility, the lenders under the Credit Facility could proceed to foreclose or otherwise realize upon the collateral granted to them to secure the indebtedness. The acceleration of the Corporation'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 Corporation that could include restrictions on the repurchase or making of other distributions with respect to the Corporation'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.

The Corporation's lenders use the Corporation's reserves, commodity prices, applicable discount rate and other factors, to periodically determine the Corporation's borrowing base. A material decline in commodity prices could reduce the Corporation's borrowing base, reducing the funds available to the Corporation under the Credit Facility. This could result in the requirement to repay a portion, or all, of the Corporation's bank indebtedness.

Substantial Capital Requirements

Spartan anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. If the Corporation's revenues or reserves decline, it may not have access to the capital necessary to undertake or complete future drilling programs. In addition, uncertain levels of near term industry activity coupled with the current commodity price environment exposes the Corporation to additional access to capital risk. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Corporation. The inability of the Corporation to access sufficient capital for its operations could have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Additional Funding Requirements

Spartan's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times. From time to time, the Corporation may require additional financing in order to carry out its oil and gas acquisition, exploration and development activities. Failure to obtain such financing on a timely basis could cause the Corporation to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If the Corporation's revenues from its reserves decrease as a result of depressed oil and natural gas prices or otherwise, it will affect the Corporation's ability to expend the necessary capital to replace its reserves or to maintain its production. If the Corporation's cash flow from operations is not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or, if available, on terms acceptable to the Corporation. Continued uncertainty in domestic and international credit markets could materially affect the Corporation's ability to access sufficient capital for its capital expenditures and acquisitions, and as a result, may have a material adverse effect on the Corporation's ability to execute its business strategy and on its business, financial condition, results of operations and prospects.

Future Sales of Common Shares

Spartan may issue additional Common Shares in the future, which may dilute a shareholder's holdings in the Corporation. Spartan's articles permit the issuance of an unlimited number of Common Shares and shareholders will have no pre-emptive rights in connection with such further issuances. Also, additional Common Shares may be issued by the Corporation on the exercise of Warrants, on the exercise of Options under the Corporation's stock option plan, or on the satisfaction of restricted share units ("**RSUs**") granted under the Corporation's RSU plan.

Finding, Developing and Acquiring Petroleum and Natural Gas Reserves on an Economic Basis

Petroleum and natural gas reserves naturally deplete as they are produced over time. The success of the Corporation's business is highly dependent on its ability to acquire and/or discover new reserves in a cost efficient manner. Substantially all of the Corporation's cash flow is derived from the sale of the petroleum and natural gas reserves it accumulates and develops. In order to remain financially viable, the Corporation must be able to replace reserves over time at a lesser cost on a per unit basis than its cash flow on a per unit basis. The reserves and costs used in this determination are estimated each year based on numerous assumptions and these estimates and costs may vary materially from the actual reserves produced or from the costs required to produce those reserves. The Corporation mitigates this risk by employing a qualified and experienced team of petroleum and natural gas professionals, operating in geological areas in which prospects are well understood by management and by closely monitoring the capital expenditures made for the purposes of increasing its petroleum and natural gas reserves.

Operational Dependence

Other companies operate some of the assets in which the Corporation has an interest. As a result, the Corporation has limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect the Corporation's financial performance. The Corporation's return on assets operated by others therefore depends upon a number of factors that may be outside of the Corporation's control, including 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.

Project Risks

Spartan 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. Spartan's ability to execute projects and market oil and natural gas depends upon numerous factors beyond Spartan's control, including:

- the availability and proximity of pipeline capacity;
- the availability of storage capacity;
- the supply of and demand for oil and natural gas;
- the availability of processing capacity;
- the availability of alternative fuel sources;
- the effects of inclement weather;
- the availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- changes in regulations;
- the availability and productivity of skilled labour; and
- the regulation of the oil and gas industry by various levels of government and governmental agencies.

Because of these factors, Spartan could be unable to execute projects on time, on budget or at all, and may not be able to effectively market the oil and natural gas that it produces.

Competition

The petroleum industry is competitive in all its phases. Spartan competes with numerous other organizations in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas. Spartan's competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than those of the Corporation. Spartan'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 and methods and reliability of delivery and storage. Competition may also be presented by alternate fuel sources.

Cost of New Technologies

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

Regulatory

Oil and natural gas operations (exploration, production, pricing, marketing and transportation) are subject to extensive controls and regulations imposed by various levels of government, which may be amended from time to time. See "*Industry Conditions*" above. Governments may regulate or intervene with respect to price, taxes, royalties and the exportation of oil and natural gas. Such regulations may be changed from time to time in response to economic or political conditions. The implementation of new regulations or the modification of existing regulations affecting the oil and gas industry could reduce demand for natural gas and crude oil and increase the Corporation's costs, any of which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In order to conduct oil and gas operations, the Corporation will require licenses from various governmental authorities. There can be no assurance that the Corporation will be able to obtain all of the licenses and permits that may be required to conduct operations that it may wish to undertake. Recently, the federal government and certain provincial governments have taken steps to initiate protocols and regulations to limit the release of methane from oil and gas operations. Such draft regulations and protocols may require additional expenditures or otherwise negatively impact Spartan's operations, which may affect the Corporation's profitability.

Fiscal and Royalty Regime

In addition to federal regulation, each province has legislation and regulations which govern land tenure, drilling and construction permits, royalties, production rates, environmental protection and other matters. See "*Industry Conditions*" above. The royalty regime is a significant factor in the profitability of oil and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiations between the mineral owner and the lessee. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the gross production, and the rate of royalties payable generally depends in part on well productivity, geographical location, field discovery data and the type or quality of the petroleum product produced.

On January 29, 2016, Alberta announced a new royalty regime, which was fully implemented as of January 1, 2017. See "*Provincial Royalties and Incentives - Alberta*" above. The royalty regime in Saskatchewan, Alberta, Manitoba and any other jurisdictions in which the Corporation's oil and natural gas assets are located may be subject to further review and changes which could adversely impact the Corporation's financial condition and operations.

Environmental

All phases of the oil and 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 spills, releases or emissions of various substances produced in association with oil and natural gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Corporation to incur costs to remedy such discharge. Although the Corporation believes that it will be in material compliance with current applicable environmental regulations, no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Although Spartan maintains insurance consistent with prudent industry practice, it is not fully insured against certain environmental risks, either because such insurance is not available or because of high premium costs. In particular, insurance against risks from environmental pollution occurring over time (as opposed to sudden and catastrophic damages) is not available on economically reasonable terms. Accordingly, Spartan's properties may be subject to liability due to hazards that cannot be insured against, or that have not been insured against due to prohibitive premium costs or for other reasons. It is also possible that changing regulatory requirements or emerging jurisprudence could render such insurance of less benefit to Spartan.

Climate Change

Canada is a signatory to the UNFCCC and has ratified the Kyoto Protocol established thereunder to set legally binding targets to reduce nationwide emissions of carbon dioxide, methane, nitrous oxide and other so-called "greenhouse gases". In December 2011, representatives from approximately 170 countries met in Copenhagen, Denmark to attempt to negotiate a successor to the Kyoto Protocol. Pursuant to the resulting Copenhagen Accord, a non-binding political consensus rather than a binding international treaty such as the Kyoto Protocol, the Government of Canada revised its emissions reduction targets slightly. There has been much public debate with respect to Canada's ability to meet these targets and the Government's strategy or alternative strategies with respect to climate change and the control of greenhouse gases. On December 12, 2011, Canada formally withdrew from the Kyoto Protocol. The impact of Canada's withdrawal from the Kyoto Protocol on prior GHG emission reduction initiatives is uncertain.

Spartan's exploration and production facilities and other operations and activities emit greenhouse gases and require the Corporation to comply with Alberta's greenhouse gas emissions legislation contained in the *Climate Change and Emissions Management Act* and the *Specified Gas Emitters Regulation*. Spartan may also be required comply with the regulatory scheme for greenhouse gas emissions ultimately adopted by the federal government, which is now expected to be modified to ensure consistency with the regulatory scheme for greenhouse gas emissions adopted by the United States. The direct or indirect costs of these regulations may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. The future implementation or modification of greenhouse gases regulations could have a material impact on the nature of oil and natural gas operations, including those of the Corporation. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict the impact on the Corporation and its operations and financial condition. See "*Industry Conditions – Environmental Regulation*" above.

On December 12, 2015, at the UNFCCC, Canada became a signatory to the Paris Agreement which has set broad goals to, among other things, limit global climate change to not more than 2 degrees Celsius (or less), preparing, maintaining and publishing national greenhouse gas reduction targets and creating a "carbon-neutral" world by 2050. As a result of the UNFCCC adopting the Paris Agreement, which Canada ratified on October 5, 2016, the Government of Canada pledged to cut its GHG 2017 emissions by 30% from 2005 levels by 2030. One of the pertinent policies announced to date by the Government of Canada to reduce GHG emission is the planned implementation of a nation-wide price on carbon emissions. Provincially, the Government of Alberta has already implemented a carbon levy on almost all sources of GHG emissions, now at a rate of $30 per tonne. The direct or indirect costs of compliance with these regulations may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. Some of the Corporation's significant facilities may ultimately be subject to future regional, provincial and/or federal climate change regulations to manage GHG emissions. In addition, concerns about climate change have resulted in a number of environmental activists and members of the public opposing the continued exploitation and development of fossil fuels. Given the evolving nature of the debate related to climate change and the control of GHG and resulting requirements, it is expected that current and future climate change regulations will have the effect of increasing the Corporation's operating expenses and in the long-term reducing the demand for oil and gas production resulting in a decrease in Spartan's profitability and a reduction in the value of the Corporation's assets or asset write-offs. See "*Climate Change Regulation*".

Variations in Foreign Exchange Rates and Interest Rates

World oil and gas prices are quoted in U.S. dollars and the price received by Canadian producers is therefore affected by the Canadian/U.S. dollar exchange rate, which will fluctuate over time. Material increases in the value of the Canadian dollar negatively impact the Corporation's production revenues. Future Canadian/U.S. dollar exchange rates could accordingly impact the future value of the Corporation's reserves as determined by independent evaluators. To the extent that the Corporation engages in risk management activities related to foreign exchange rates, there is a credit risk associated with counterparties with which the Corporation may contract. Furthermore, an increase in interest rates could result in a significant increase in the amount the Corporation pays to service debt, which could negatively impact the market price of the Common Shares.

Issuance of Debt

From time to time the Corporation may enter into transactions to acquire assets or the shares of other organizations. These transactions may be financed in whole or in part with debt, which may increase the Corporation's debt levels above industry standards for oil and natural gas companies of similar size. Depending on future exploration and development plans, the Corporation may require additional equity and/or debt financing that may not be available or, if available, may not be available on favourable terms. Neither the Corporation's articles nor its by-laws limit the amount of indebtedness that the Corporation may incur. The level of the Corporation's indebtedness from time to time could impair the Corporation'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 Corporation 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, if commodity prices increase beyond the levels set in such agreements, the Corporation will not benefit from such increases and the Corporation may nevertheless be obligated to pay royalties on such higher prices, even though not received by it, after giving effect to such agreements. Similarly, from time to time the Corporation may enter into agreements to fix the exchange rate of Canadian to U.S. dollars in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the U.S. dollar; however, if the Canadian dollar declines in value compared to the U.S. dollar, the Corporation will not benefit from the fluctuating exchange rate. See *"Other Oil and Gas Information - Forward Contracts and Marketing*" for additional information.

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) in the particular areas where such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to the Corporation and may delay exploration and development activities.

Title to Assets

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat the Corporation's claim, which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

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 herein are estimates only. In general, estimates of economically recoverable oil and natural gas reserves and the future net cash flows therefrom 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 gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially from actual results. For those reasons, estimates of the economically recoverable 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. Spartan's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material. Further, the evaluations are based in part on the assumed success of exploitation activities intended to be undertaken in future years. The reserves and estimated cash flows to be derived therefrom contained in such evaluations will be reduced to the extent that such exploitation activities do not achieve the level of success assumed in the evaluation.

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

There are numerous uncertainties inherent in estimating quantities of resources, including many factors beyond the Corporation's control. No assurance can be given that the indicated level of resources will be realized. In general, estimates of recoverable resources are based upon a number of factors and assumptions made as of the date on which the resource estimates were determined, such as geological and engineering estimates which have inherent uncertainties, the assumed effects of regulation by governmental agencies and estimates of future commodity prices and operating costs, all of which may vary considerably from actual results. All such estimates are, to some degree, uncertain and classifications of resources are only attempts to define the degree of uncertainty involved. For these reasons, estimates of the economically recoverable natural gas and the classification of such resources based on risk of recovery prepared by different engineers or by the same engineers at different times may vary substantially.

Geological risking of prospective resources addresses the probability of success for the discovery of petroleum; this risk analysis is conducted independently of probabilistic estimates of petroleum volumes and without regard to the chance of development. Principal risk elements of the petroleum system include: (i) trap and seal characteristics; (ii) reservoir presence and quality; (iii) source rock capacity, quality and maturity; and (iv) timing, migration and preservation of petroleum in relation to trap and seal formation. Geological risk assessment is a highly subjective process dependent upon the experience and judgment of the evaluators.

In accordance with applicable securities laws, the Corporation'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.

Reserve Replacement

Spartan's future oil and natural gas reserves, production, and cash flows to be derived therefrom are highly dependent on Spartan successfully acquiring or discovering new reserves. Without the continual addition of new reserves, any existing reserves Spartan may have at any particular time and the production therefrom will decline over time as such existing reserves are exploited. A future increase in Spartan's reserves will depend not only on Spartan's ability to develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. There can be no assurance that Spartan's future exploration and development efforts will result in the discovery and development of additional commercial accumulations of oil and natural gas.

Insurance

Spartan's involvement in the exploration for and development of oil and natural gas properties may result in the Corporation becoming subject to liability for pollution, blow outs, leaks of sour natural gas, property damage, personal injury or other hazards. Although the Corporation 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, such risks are not, in all circumstances, insurable or, in certain circumstances, the Corporation 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 Corporation. The occurrence of a significant event that the Corporation is not fully insured against, or the insolvency of the insurer of such event, may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Geo-Political Risks

The marketability and price of oil and natural gas that may be acquired or discovered by the Corporation is and will continue to be affected by political events throughout the world that cause disruptions in the supply of oil. Conflicts, or conversely peaceful developments, arising in the Middle-East, and other areas of the world, have a significant impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and therefore result in a reduction of the Corporation's net production revenue.

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

Management of Growth

Spartan may be subject to growth-related risks including capacity constraints and pressure on its internal systems and controls. The ability of the Corporation 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 Corporation to deal with this growth may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Expiration of Licences and Leases

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

Litigation

In the normal course of the Corporation's operations, it may become involved in, named as a party to, or be the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions, related to personal injuries, property damage, property tax, land rights, the environment and contract disputes. The outcome of outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to the Corporation and as a result, could have a material adverse effect on the Corporation's assets, liabilities, business, financial condition and results of operations.

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights to portions of Western Canada. Spartan 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 Corporation's business, financial condition, results of operations and prospects.

Dividends

Spartan 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 Corporation, the need for funds to finance ongoing operations and other considerations as the Board of Directors considers relevant.

Breach of Confidentiality

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

Seasonality and Extreme Weather Conditions

The level of activity in the Canadian oil and 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. Roads bans and other restrictions generally result in a reduction of drilling and exploratory activities and may also result in the shut-in of some of the Corporation's production if not otherwise tied-in. Also, certain oil and 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 Spartan's ability to access its properties, cause operational difficulties including damage to machinery or contribute to personnel injury because of dangerous working conditions. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and corresponding declines in the demand for the goods and services of the Corporation.

Third Party Credit Risk

Spartan 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 the event such entities fail to meet their contractual obligations to the Corporation, such failures may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In addition, poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in the Corporation's ongoing capital program, potentially delaying the program and the results of such program until the Corporation finds a suitable alternative partner.

Conflicts of Interest

Certain directors of the Corporation are also directors of other oil and gas companies and as such may, in certain circumstances, have a conflict of interest requiring them to abstain from certain decisions. Conflicts, if any, will be subject to the procedures and remedies of the ABCA.

Reliance on Key Personnel

Spartan'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 Corporation's business, financial condition, results of operations and prospects. Spartan does not have any key person insurance. The contributions of the existing management team to the immediate and near term operations of the Corporation are likely to be of central importance. In addition, the competition for qualified personnel in the oil and gas industry is intense and there can be no assurance that the Corporation 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 Corporation.

Expansion into New Activities

The operations and expertise of the Corporation's management are currently focused primarily on oil and gas production, exploration and development in Western Canada. In the future the Corporation 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 Corporation's exposure to one or more existing risk factors, which may in turn result in the Corporation's future operational and financial conditions being adversely affected.

Alternatives to and Changing Demand for Petroleum Products

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas, and technological advances in fuel economy and renewable energy generation devices could reduce the demand for crude oil and liquid hydrocarbons. Recently, certain jurisdictions have implemented policies or incentives to decrease the use of fossil fuels and encourage the use of renewable fuel alternatives, which may lessen the demand for petroleum products and put downward pressure on commodity prices. In addition, advancements in energy efficient products have a similar effect on the demand for oil and gas products. Spartan 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 Corporation's business, financial condition, results of operations and cash flows .

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

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

Hydraulic Fracturing

The proliferation of the use of hydraulic fracturing as a recovery technique employed in oil and natural gas drilling has given rise to increased public scrutiny of its environmental aspects, particularly with respect to its potential impact on local aquifers. Spartan utilizes hydraulic fracturing in a portion of the light oil wells it drills and completes. Negative public perception of hydraulic fracturing may place pressure on governments in the jurisdictions where Spartan operates to implement additional regulatory requirements or limitations on the utilization of hydraulic fracturing, which in turn could restrict Spartan's operations and increase its costs.

Waterflood

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

Liability Management

Alberta and Saskatchewan have developed liability management programs designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licensee or permit holder is unable to satisfy its regulatory obligations. These programs involve an assessment of the ratio of a licensee's deemed assets to deemed liabilities. If a licensee's deemed liabilities exceed its deemed assets, a security deposit is generally required. Changes to the required ratio of Spartan's deemed assets to deemed liabilities or other changes to the requirements of liability management programs may result in significant increases to the Corporation's compliance obligations. In addition, the liability management regime may prevent or interfere with the Corporation's ability to acquire or dispose of assets, as both the vendor and the purchaser of oil and gas assets must be in compliance with the liability management programs (both before and after the transfer of the assets) for the applicable regulatory agency to allow for the transfer of such assets. The recent Alberta Court of Queen's Bench decision, Redwater, found an operational conflict between the BIA and the AER's abandonment and reclamation powers when the licensee is insolvent, which was affirmed by a majority of the Alberta Court of Appeal, and has been appealed by the AER to the Supreme Court of Canada for final determination. In response to the decision, the AER issued interim rules to administer the liability management program and until the Government of Alberta can develop new regulatory measures to adequately address environmental liabilities. There remains a great deal of uncertainty as to what new regulatory measures will be developed by the provinces or in concert with the federal government, as the final ruling will become binding in all Canadian jurisdictions. See "*Liability Management Rating Programs*".

Gathering and Processing Facilities, Pipeline Systems and Rail

Spartan 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 Corporation can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering and processing facilities, pipeline systems and railway lines. The lack of availability of capacity in any of the gathering and processing facilities, pipeline systems and railway lines could result in Spartan's inability to realize the full economic potential of its production or in a reduction of the price offered for its 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 Corporation'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 Corporation's business and, in turn, its financial condition, operations and cash flows. Announcements and actions taken by the governments of British Columbia and Alberta relating to approval of infrastructure projects may continue to intensify, leading to increased challenges to interprovincial and international infrastructure projects moving forward. In addition, while the federal government has recently introduced draft legislation to overhaul the existing environmental assessment process and replace the NEB with a new regulatory agency, the impact of the new proposed regulatory scheme on proponents and the timing of receipt of approvals of major projects remains unclear.

Following major accidents in Lac-Megantic, Quebec and North Dakota, the Transportation Safety Board of Canada and the U.S. National Transportation Board have recommended additional regulations for railway tank cars carrying crude oil. 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 Spartan's production may, from time to time, be processed through facilities owned by third parties and over which Spartan 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 Spartan's ability to process its production and deliver the same for sale. Midstream and pipeline companies may take actions to maximize their return on investment which may in turn adversely affect producers and shippers, especially when combined with a regulatory framework that may not always align with the interests of particular shippers.

Information Technology Systems and Cyber-Security

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

Further, Spartan 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 its 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 its business activities or its competitive position. In addition, cyber phishing attempts, in which a malicious party attempts to obtain sensitive information such as usernames, passwords, and credit card details (and money) by disguising as a trustworthy entity in an electronic communication, have become more widespread and sophisticated in recent years. If Spartan becomes a victim to a cyber phishing attack it could result in a loss or theft of the Corporation's financial resources or critical data and information or could result in a loss of control of its technological infrastructure or financial resources. Spartan applies technical and process controls in line with industry-accepted standards to protect its information assets and systems; however, these controls may not adequately prevent cyber-security breaches. Disruption of critical information technology services, or breaches of information security, could have a negative effect on Spartan's performance and earnings, as well as on its reputation. 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 its business, financial condition and results of operations.

Disposal of Fluids Used in Operations

The safe disposal of the hydraulic fracturing fluids (including the additives) and water recovered from oil and natural gas wells is subject to ongoing regulatory review by the federal and provincial governments, including its effect on fresh water supplies and the ability of such water to be recycled, amongst other things. While it is difficult to predict the impact of any regulations that may be enacted in response to such review, the implementation of stricter regulations may increase Spartan's costs of compliance.

Carbon Pricing Risk

The majority of countries across the globe have agreed to reduce their carbon emissions in accordance with the Paris Agreement. See "*Climate Change Regulation*". In Canada, the federal and certain provincial governments have implemented legislation aimed at incentivizing the use of alternatives fuels and in turn reducing carbon emissions. The taxes placed on carbon emissions may have the effect of decreasing the demand for oil and natural gas products and at the same time, increasing Spartan's operating expenses, each of which may have a material adverse effect on the Corporation's profitability and financial condition. Further, the imposition of carbon taxes puts the Corporation at a disadvantage with Spartan's counterparts who operate in jurisdictions where there are less costly carbon regulations.

Reputational Risk Associated with Operations

Any environmental damage, loss of life, injury or damage to property caused by Spartan's operations could damage its reputation in the areas in which the Corporation operates. Negative sentiment towards Spartan could result in a lack of willingness of municipal authorities being willing to grant the necessary licenses or permits for the Corporation to operate its business and in residents in the areas where Spartan is doing business opposing the Corporation's further operations in the area. If Spartan develops a reputation of having an unsafe work site it may impact the Corporation's ability to attract and retain the necessary skilled employees and consultants to operate its business. Further, Spartan's reputation could be affected by actions and activities of other corporations operating in the oil and gas industry, over which Spartan has no control. In addition, environmental damage, loss of life, injury or damage to property caused by Spartan's operations could result in negative investor sentiment towards the Corporation, which may result in limiting Spartan's access to capital, increasing the cost of capital, and decreasing the price and liquidity of the Common Shares.

Changing Investor Sentiment

A number of factors, including the concerns of the effects of the use of fossil fuels on climate change, concerns of the impact of oil and gas operations on the environment, concerns of environmental damage relating to spills of petroleum products during transportation and concerns of indigenous rights, have affected certain investors' sentiments towards investing in the oil and gas industry. As a result of these concerns, some institutional, retail and public investors have announced that they no longer are willing to fund or invest in oil and gas properties or companies or are reducing the amount thereof over time. In addition, certain institutional investors are requesting that issuers develop and implement more robust social, environmental and governance policies and practices. Developing and implementing such policies and practices can involve significant costs and require a significant time commitment from Spartan's Board, management and employees. Failing to implement the policies and practices as requested by institutional investors may result in such investors reducing their investment in the Corporation or not investing in Spartan at all. Any reduction in the investor base interested or willing to invest in the oil and gas industry and more specifically, the Corporation, may result in limiting Spartan's access to capital, increasing the cost of capital, and decreasing the price and liquidity of the Common Shares.

Forward-Looking Information May Prove to be Inaccurate

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

Additional information on the risks, assumptions and uncertainties are found in this Annual Information Form under the heading "*Forward-Looking Statements*" above.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Disclosure of Reserves Data and Other Information for the Financial Year Ended December 31, 2017

The reserves data herein is based upon a report prepared by Sproule, dated February 20, 2018, with an effective date of December 31, 2017 (the "**Spartan Reserve Report**") evaluating the crude oil, natural gas liquids and natural gas reserves of Spartan as at December 31, 2017. The reserves data set forth below is based upon an evaluation of the Spartan Reserve Report. The Spartan Reserve Report summarizes the crude oil, natural gas liquids and natural gas reserves of Spartan and the net present values of future net revenue for these reserves using forecast prices and costs. The Spartan Reserve Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101. Additional information not required by NI 51-101 has been presented to provide continuity and additional information which Spartan believes is important to the readers of this information. The following tables provide summary information presented in the Spartan Reserve Report effective December 31, 2017 and based on the Sproule December 31, 2017 price forecast.

As of the date hereof, Spartan's reserves are located in the provinces of Alberta, Saskatchewan and Manitoba.

The Report on Reserves Data by Sproule and the Report of Management and Directors on Oil and Gas Disclosure are attached as Appendix A and Appendix B, respectively, to this Annual Information Form.

It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the Corporation's reserves. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. The recovery and reserve estimates of Spartan's crude oil, natural gas liquids and conventional natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, conventional natural gas and natural gas liquid reserves may be greater than or less than the estimates provided herein.

SUMMARY OF OIL AND GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF DECEMBER 31, 2017
FORECAST PRICES AND COSTS

	Light and Medium Crude Oil		**Conventional Natural Gas (associated & non-associated)**		**Natural Gas Liquids**		**Barrels of Oil Equivalent**	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
	(Mbbl)	(Mbbl)	(MMcf)	(MMcf)	(Mbbl)	(Mbbl)	(MBOE)	(MBOE)
Proved								
Developed Producing	40,814.1	36,447.7	15,659	13,866	1,868.7	1,687.6	45,292.6	40,446.3
Developed Non-Producing	513.7	464.4	569	498	42.1	36.4	650.7	583.8
Undeveloped	21,913.9	19,717.1	20,101	17,718	1,762.2	1,557.6	27,026.2	24,227.7
Total Proved	63,241.6	56,629.2	36,329	32,082	3,673.0	3,281.6	72,969.5	65,257.8
Probable	36,151.3	32,228.7	16,185	14,062	1,667.0	1,469.8	40,515.7	36,042.2
Total Proved plus Probable	99,392.9	88,857.9	52,514	46,144	5,340.0	4,751.5	113,485.2	101,300.1

Notes:
(1) Columns may not add due to rounding.
(2) Conventional natural gas volumes include solution gas volumes associated with Spartan's light and medium crude oil reserves.
(3) Conventional natural gas is converted to a BOE at a ratio of six thousand standard cubic feet to one barrel of oil.

	Net Present Value of Future Net Revenue										
	Before Income Tax Discounted at Various Rates					**After Income Tax Discounted at Various Rates**					**BT Unit Value (discounted at 10% ($/BOE))**
	0%	**5%**	**10%**	**15%**	**20%**	**0%**	**5%**	**10%**	**15%**	**20%**	
Entity Description	**M$**	**M$**	**M$**	**M$**	**M$**	**M$**	**M$**	**M$**	**M$**	**M$**	
Proved											
Producing	1,387,114	1,040,839	841,299	711,040	618,993	1,387,114	1,040,839	841,299	711,040	618,993	$20.80
Developed Nonproducing	16,905	13,573	11,082	9,218	7,802	16,905	13,573	11,082	9,218	7,802	$18.98
Undeveloped	682,705	478,541	347,562	258,747	195,610	596,794	424,355	312,092	234,780	178,969	$14.35
Total Proved	2,086,724	1,532,953	1,199,943	979,005	822,405	2,000,813	1,478,767	1,164,472	955,038	805,764	$18.39
Total Probable	1,654,499	1,056,761	756,969	578,873	462,151	1,208,081	771,594	553,740	425,216	341,515	$21.00
Total Proved plus Probable	3,741,223	2,589,715	1,956,912	1,557,878	1,284,557	3,208,895	2,250,361	1,718,213	1,380,254	1,147,279	$19.32

Notes:
(1) Utilizes Sproule's price forecast as of December 31, 2017 as detailed below.
(2) Values are net of abandonment liabilities.
(3) Columns may not add due to rounding.
(4) BT Unit Value is the unit value before income tax discounted at 10% per year.

TOTAL FUTURE NET REVENUE (UNDISCOUNTED) AS OF DECEMBER 31, 2017
FORECAST PRICES AND COSTS

RESERVES CATEGORY	REVENUE (M$)	ROYALTIES (M$)	OPERATING COSTS (M$)	CAPITAL DEVELOPMENT COSTS (M$)	ABANDONMENT/ OTHER COSTS (M$)	FUTURE NET REVENUE BEFORE INCOME TAXES (M$)	INCOME TAX (M$)	FUTURE NET REVENUE AFTER INCOME TAXES (M$)
Proved	5,535,577	721,451	1,988,821	543,248	195,333	2,086,724	85,910	2,000,813
Proved Plus Probable	8,973,612	1,167,331	3,018,477	810,716	235,864	3,741,223	532,328	3,208,895

FUTURE NET REVENUE BY PRODUCTION GROUP
AS OF DECEMBER 31, 2017
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE TAXES (discounted at 10%/year) (M$)	UNIT VALUE BEFORE INCOME TAX(2) (discounted at 10%/year ($/BOE))
Proved	Light and Medium Crude Oil (including solution gas and other by-products)	1,199,983	$18.39
	Conventional Natural Gas (including associated by-products)	(41)	$(3.61)
	Total	1,199,943	
Proved Plus Probable	Light and Medium Crude Oil (including solution gas and other by-products)	1,956,936	$19.32
	Conventional Natural Gas (including associated by-products)	(25)	$(1.75)
	Total	1,956,912	

Notes:
(1) Columns may not add due to rounding.
(2) Unit values are based on net reserve volumes.

Reserve Categories

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

- analysis of drilling, geological, geophysical and engineering data;
- the use of established technology; and
- specified economic conditions, specifically the forecast prices and costs.

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

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

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

Other criteria that must also be met for the categorization of reserves are provided in the COGE Handbook.

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

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

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

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

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

In multi-well pools it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide 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.

Levels of Certainty for Reported Reserves

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

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

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

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

Additional clarification of certainty levels associated with reserves estimates and the effect of aggregation is provided in the COGE Handbook.

Interests in Reserves, Production, Wells and Properties

An issuer's interest in reserves, production, wells and properties can be reported in a number of ways:

(a) "**gross**" means: (i) in relation to an issuer's interest in production or reserves, its "company gross reserves", which are its working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests of the issuer; (ii) in relation to wells, the total number of wells in which an issuer has an interest; and (iii) in relation to properties, the total area of properties in which an issuer has an interest.

(b) "**net**" means: (i) in relation to an issuer's interest in production or reserves its working interest (operating or non-operating) share after deduction of royalty obligations, plus its royalty interests in production or reserves; (ii) in relation to an issuer's interest in wells, the number of wells obtained by aggregating the issuer's working interest in each of its gross wells; and (iii) in relation to an issuer's interest in a property, the total area in which the issuer has an interest multiplied by the working interest owned by the issuer.

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

Description of Exploration and Development Wells and Costs

"**development costs**" means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the crude oil and natural gas from the reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to: (i) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines and power lines, to the extent necessary in developing the reserves; (ii) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and wellhead assembly; (iii) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and (iv) provide improved recovery systems.

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

"**exploration costs**" means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and natural gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as "prospecting costs") and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are: (i) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies (collectively sometimes referred to as "geological and geophysical costs"); (ii) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence, and the maintenance of land and lease records; (iii) dry hole contributions and bottom hole contributions; (iv) costs of drilling and equipping exploratory wells; and (v) costs of drilling exploratory type stratigraphic test wells.

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

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

Forecast Costs and Price Assumptions

The forecast cost and price assumptions assume increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs. Crude oil and natural gas benchmark reference pricing, inflation and exchange rates utilized by Sproule in the Spartan Reserve Report were Sproule's forecasts, as at December 31, 2017, as follows:

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
FORECAST PRICES AND COSTS

Year	WTI Cushing Oklahoma 40° API ($US/Bbl)	Canadian Light Sweet 40° API ($Cdn/Bbl)	Cromer LSB 35° API ($Cdn/Bbl)	Natural Gas AECO ($Cdn/MMBTU)	Edmonton Propane ($Cdn/Bbl)	Edmonton Butane ($Cdn/Bbl)	Operating Cost Inflation Rate %/year	Capital Cost Inflation Rate %/year	Exchange Rate ($US/$Cdn)
2018	55.00	65.44	64.44	2.85	26.06	48.73	0	0	0.79
2019	65.00	74.51	73.51	3.11	32.84	55.49	2	2	0.82
2020	70.00	78.24	77.24	3.65	35.41	57.65	2	2	0.85
2021	73.00	82.45	81.45	3.80	37.85	60.12	2	2	0.85
2022	74.46	84.10	83.10	3.95	39.29	61.32	2	2	0.85
2023	75.95	85.78	84.78	4.05	40.25	62.55	2	2	0.85
2024	77.47	87.49	86.49	4.15	41.23	63.80	2	2	0.85
2025	79.02	89.24	88.24	4.25	42.23	65.07	2	2	0.85
2026	80.60	91.03	90.03	4.36	43.26	66.37	2	2	0.85
2027	82.21	92.85	91.85	4.46	44.30	67.70	2	2	0.85
2028	83.85	94.71	93.71	4.57	45.36	69.06	2	2	0.85
Thereafter	Escalation Rate of 2.0%								

Weighted average historical prices realized for the year ended December 31, 2017, after hedging, was $57.32/Bbl for crude oil, $29.30/Bbl for NGLs and $2.67/Mcf for natural gas.

Estimated future abandonment and reclamation costs related to a working interest have been taken into account by Sproule for all entities assigned reserves within a property and in determining the aggregate future net revenue therefrom, there was deducted the reasonable estimated future well abandonment and reclamation costs. No allowance was made, however, for the reclamation or the abandonment of any major facilities. The forecast price and cost assumptions assume the continuance of current laws and regulations.

Reconciliations of Changes in Reserves and Future Gross Revenue

The following sets out the reconciliation of Spartan's gross reserves based on forecast prices and costs by principal product type:

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

	Light and Medium Crude Oil			Natural Gas Liquids		
Factors	**Gross Proved (Mbbl)**	**Gross Probable (Mbbl)**	**Gross Proved + Probable (Mbbl)**	**Gross Proved (Mbbl)**	**Gross Probable (Mbbl)**	**Gross Proved + Probable (Mbbl)**
December 31, 2016	59,610.8	34,965.4	94,576.2	3,075.5	1,624.4	4,699.9
Discoveries	-	-	-	-	-	-
Extensions and Improved Recovery	3,607.8	3,994.2	7,602.0	242.1	120.1	362.2
Infill Drilling	3,698.6	2,227.0	5,925.6	204.4	67.5	271.9
Technical Revisions	2,023.1	(5,517.8)	(3,494.7)	438.6	(145.0)	293.6
Acquisitions	1,251.7	371.2	1,622.9	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	136.6	111.3	247.9	(1.1)	-	(1.1)
Production	(7,087.0)	-	(7,087.0)	(286.5)	-	(286.5)
December 31, 2017	63,241.6	36,151.3	99,392.9	3,673.0	1,667.0	5,340.0

	Associated and Non-Associated Conventional Natural Gas			Natural Gas Solution		
Factors	**Gross Proved (Mmcf)**	**Gross Probable (Mmcf)**	**Gross Proved + Probable (Mmcf)**	**Gross Proved (Mmcf)**	**Gross Probable (Mmcf)**	**Gross Proved + Probable (Mmcf)**
December 31, 2016	258	72	330	38,874	19,908	58,782
Discoveries	-	-	-	-	-	-
Extensions and Improved Recovery	-	-	-	2,143	1,241	3,384
Infill Drilling	-	-	-	2,256	680	2,936
Technical Revisions	(163)	(55)	(218)	(2,886)	(5,665)	(8,551)
Acquisitions	-	-	-	2	1	3
Dispositions	-	-	-	-	-	-
Economic Factors	(2)	(3)	(5)	(26)	6	(20)
Production	(41)	-	(41)	(4,086)	-	(4,086)
December 31, 2017	52	14	66	36,277	16,171	52,448

Reserves Data

Undeveloped Reserves

The following tables set forth the proved undeveloped reserves and the probable undeveloped reserves, each by product type, first attributed to the Corporation’s reserves in each of the following financial years.

Proved Undeveloped Reserves

	Light and Medium Crude Oil (Mbbl)		Conventional Natural Gas (MMcf)		Natural Gas Liquids (Mbbl)	
	First Attributed Gross	Booked Gross	First Attributed Gross	Booked Gross	First Attributed Gross	Booked Gross
December 31, 2015	2,216.3	9,246.1	77.0	713.0	16.4	113.3
December 31, 2016	10,432.5	18,596.9	13,688.0	22,595.0	863.6	1,586.6
December 31, 2017	5,493.4	21,913.9	3,265.0	20,101.0	328.4	1,762.2

Probable Undeveloped Reserves

	Light and Medium Crude Oil (Mbbl)		Conventional Natural Gas (MMcf)		Natural Gas Liquids (Mbbl)	
	First Attributed Gross	Booked Gross	First Attributed Gross	Booked Gross	First Attributed Gross	Booked Gross
December 31, 2015	3,939.1	10,938.1	86.0	870.0	16.3	129.1
December 31, 2016	13,957.7	19,865.5	11,951.0	12,496.0	796.6	951.2
December 31, 2017	5,814.4	21,760.3	1,523.0	8,994.0	146.3	871.4

In general, once proved and/or probable undeveloped reserves are identified, they are scheduled into Spartan's development plans. Spartan plans to develop its proved and probable undeveloped reserves within five years. Sproule's evaluation documented in the Spartan Reserve Report includes undeveloped locations with development timing beyond the COGE Handbook recommended guidance of three years for the assignment of proved reserves and five years for the assignment of probable reserves. This delay has no consequent impact on the confidence level associated with the reserves estimate in each category, and the Company provides assurance for their corporate commitment for development. The following table lists the properties with future development plans that differ from the COGE Handbook guidance of three years for proved undeveloped locations and five years for probable undeveloped locations.

Property	Final Year of Development Plan		Rationale for Development Timing
	Proved	Probable	
Weyburn Unit	2024	2024	A miscible CO_2 EOR project with ongoing, extensive development opportunity. Development deferral is designed to align future capital investments with estimated future cash flow.

Spartan's timeline for developing undeveloped reserves reflect the Corporations' business plan of maintaining sustainable long term production growth while managing corporate declines. A number of factors that could result in delayed or cancelled development are as follows:

- changing economic conditions (due to pricing, operating and capital expenditure fluctuations);
- changing technical conditions (including 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);
- availability and allocation of capital based on other opportunities available to Spartan in any given year;

- 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

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 reserve estimates contained herein are based on current production forecasts, prices and economic conditions and other factors and assumptions that may affect the reserve 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 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, reserve 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, prices, economic conditions and government restrictions. Revisions to reserve estimates can arise from changes in year-end prices, reservoir performance and geologic conditions or production. These revisions can be either positive or negative.

Spartan does not anticipate any unusually high development costs or operating costs, the need to build a major pipeline or other major facility before production of reserves can begin, or 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.

Future Development Costs

The following table sets forth development costs deducted in the estimation of Spartan's future net revenue attributable to the reserve categories noted below:

	Forecast Prices and Costs (M$)	
Year	**Proved Reserves**	**Proved Plus Probable Reserves**
2018	175,250.2	178,634.9
2019	149,242.0	174,965.0
2020	95,177.0	164,801.6
2021	46,663.4	171,178.5
2022	10,664.7	11,836.2
Thereafter	66,250.3	109,300.2
Total Undiscounted	$543,247.6	$810,716.4
Total Discounted at 10%	$436,365.0	$620,216.8

The future development costs are capital expenditures required in the future for Spartan to convert proved undeveloped reserves and probable undeveloped reserves to proved developed producing reserves. The undiscounted development costs are $543.2 million for proved reserves and $810.7 million for proved plus probable reserves (in each case based on forecast prices and costs).

On an ongoing basis, Spartan will use internally generated cash flow from operations, debt and new equity issues, if available on favourable terms, to finance its capital expenditure program. The cost of funding is not expected to have any effect on disclosed reserves or future net revenue nor make the development of a property uneconomic for Spartan.

Other Oil and Gas Information

Principal Properties

Southeast Saskatchewan

The southeast Saskatchewan properties consist of approximately 402,449 net acres of land focused primarily on conventional open-hole horizontal wells drilled on Mississippian oil plays, including the Frobisher, Alida, Souris Valley, Tilston, Midale and Ratcliffe formations. Of this acreage, approximately 77,750 net acres are prospective for drilling fracture stimulated horizontal wells in the Midale formation. In addition, Spartan has approximately 22,629 net acres of land prospective for drilling fracture stimulated horizontal wells in the Torquay formation and 39,221 net acres of land prospective for drilling open-hole horizontal wells in the Ratcliffe formation.

The southeast Saskatchewan assets also include working interest ownership in the Weyburn Unit and Midale Unit in southeast Saskatchewan, which are the two largest CO_2 enhanced recovery projects in Canada.

Spartan owns producing infrastructure across its southeast Saskatchewan asset base, including gathering lines, multi-well batteries, water disposal and an interest in the Nottingham gas processing plant. At its Alameda property, Spartan has a dedicated contract to process natural gas volumes through Steel Reef's processing plant.

In 2017, Spartan drilled 61.7 net open-hole wells and brought 63.7 net open-hole wells on production; drilled 22.4 net frac Midale wells and brought 21.6 net frac Midale wells on production; drilled 2.2 net frac Torquay wells and brought 1.2 net frac Torquay wells on production; and drilled and brought on production 10.5 net Ratcliffe open-hole wells. Spartan also drilled 2.0 net stratigraphic test wells and re-entered or re-completed 1.0 net existing well. The Corporation anticipates that its 2018 capital program will be primarily focused on the continued development of its southeast Saskatchewan assets. As at the date hereof, Spartan intends to drill approximately 64.1 net open-hole wells, 30.0 net frac Midale wells and 29.3 net Ratcliffe open-hole wells on its southeast Saskatchewan assets in 2018.

West Central Saskatchewan

The west central Saskatchewan property includes approximately 37,633 net acres of land targeting the Viking formation. In 2017, Spartan completed and put on production 18.5 net frac Viking wells. As of the date hereof, Spartan intends to drill an additional 13.5 net Viking wells in west central Saskatchewan in 2018.

Manitoba

The Manitoba property includes approximately 2,765 net acres of land in the Waskada and Birdtail areas of southwest Manitoba targeting the Spearfish/Amaranth and Bakken formations. The Corporation did not drill any wells in Manitoba in 2017 and does not plan to drill additional wells in 2018.

Alberta

The Alexander property is located northwest of Edmonton in Townships 55-56, Ranges 26-27, W4M. The Corporation holds approximately 20,788 net acres of land in Alberta. Since 2011, the Corporation has drilled, cased completed and tied-in six successful oil wells in the Detrital zone on the lands. The Corporation did not drill any wells in Alberta in 2017 but plans to drill 2.5 net wells in 2018. Spartan also owns and operates a gas processing plant and oil battery in the area complete with an amine plant and salt water disposal facilities.

Oil and Gas Wells

The following table sets forth the number and status of wells in which Spartan had a working interest as at December 31, 2017.

	Producing				**Non-Producing** [(3)(4)]			
	Oil		**Gas**		**Oil**		**Gas**	
	Gross[(1)]	**Net**[(2)]	**Gross**[(1)]	**Net**[(2)]	**Gross**[(1)]	**Net**[(2)]	**Gross**[(1)]	**Net**[(2)]
Alberta	13	11.4	6	3.0	17	16.1	10	6.6
Saskatchewan	3,547	2,252.9	-	-	2,405	1,179.0	52	40.5
Manitoba	18	16.5	-	-	3	3.0	-	-
Total	3,578	2,280.8	6	3.0	2,425	1,198.1	62	47.1

Notes:
(1) "Gross" means total number of wells in which Spartan holds an interest.
(2) "Net" means the aggregate of the percentage working interests of Spartan in the gross wells.
(3) "Non-Producing" means wells that may or may not have been previously on production and the date production will be obtained from these wells is uncertain.
(4) Does not include wells that have been abandoned and are awaiting reclamation.

Properties with No Attributable Reserves

The following table summarizes Spartan's undeveloped land holdings (in acres) as at December 31, 2017. All of the Company's land holdings are in Canada.

	Unproved Properties		
	Gross[(1)]	**Net**[(2)]	**Net Acres Expiring Within One Year**
Total	250,575	229,175	14,056

Notes:
(1) "Gross" means the total number of acres in which Spartan holds an interest.
(2) "Net" means the aggregate of the percentage working interests of Spartan in the gross acres.

Forward Contracts and Marketing

Spartan markets the majority of its production on month to month contracts on spot market terms and as at the date hereof has no forward commodity contracts in place.

Additional Information Concerning Abandonment and Reclamation Costs

Spartan estimates well abandonment and reclamation costs on an area by area basis using historical costs and supplemented by current industry costs and changes in regulatory requirements. If representative comparisons are not readily available, an estimate is prepared based on the various regulatory abandonment requirements.

Estimated abandonment and reclamation costs for wells that have been assigned reserves were included in the Spartan Reserve Report as a deduction in determining future net revenue. The total estimated abandonment and reclamation costs in respect of proved reserves using forecast prices with respect to 1,970 net wells is $195.3 million undiscounted ($37.2 million using a 10% discount rate). All of such amounts were deducted as abandonment and reclamation costs in estimating future net revenue of Spartan in respect of proved reserves as disclosed above. No allowance for salvage value was included in these costs. The total proved plus probable abandonment and reclamation costs are $235.9 million (undiscounted) and $32.9 million (discounted at 10%) for 2,302 net wells. The following tables set forth the timing of abandonment and reclamation costs deducted in the estimation of Spartan's future net revenue:

Forecast Prices and Costs (Total Proved) (M$)

Year	Abandonment Costs (Undiscounted)
2018	437.8
2019	437.8
2020	446.5
Thereafter	194,011.3
Total Undiscounted	195,333.4
Total Discounted at 10%	37,168.5

Forecast Prices and Costs (Total Proved & Probable) (M$)

Year	Abandonment Costs (Undiscounted)
2018	437.8
2019	437.8
2020	446.5
Thereafter	234,542.4
Total Undiscounted	235,864.5
Total Discounted at 10%	32,863.4

Expected reclamation costs for surface leases, reclamation and remediation costs for facilities and abandonment costs for wells not assigned reserves are not included in the Spartan Reserve Report as deductions in arriving at future net revenue. Spartan has estimated expected total costs related to these of $258.4 million undiscounted ($15.7 million discounted at 10%) as of December 31, 2017. Decommissioning liabilities as recorded in the December 31, 2017 annual consolidated financial statements will not equal the aggregate of the amounts described above as such liabilities are calculated using a different discount rate.

Tax Horizon

Depending on levels of production, commodity prices, acquisitions and capital expenditures, Spartan will not pay current income taxes until at least 2024.

Costs Incurred

The following table summarizes the cash capital expenditures incurred by Spartan for property acquisitions, exploration activities and development activities for the year ended December 31, 2017:

	Canada (M$)
Property Acquisition Costs	
Proved Properties	27,385
Unproved Properties	7,987
Exploration Costs	1,944
Development Costs	142,956
Total:	180,272

Capital Expenditures

The following table summarizes the cash capital expenditures incurred by Spartan for the year ended December 31, 2017:

	(M$)
Drilling and completions	102,507
Equipment, facilities and CO2 EOR capital	34,499
Other	3,524
Land and seismic	9,170
Waterflood capital	3,187
Acquisitions	27,385
Total capital expenditures	180,272

Exploration and Development Activities

The following table sets forth the gross and net exploratory and development wells in which Spartan participated during the year ended December 31, 2017:

Canada	**Exploration**		**Development**	
	Gross	**Net**	**Gross**	**Net**
Light and Medium Crude Oil	-	-	141	117.0
Conventional Natural Gas	-	-	-	-
Stratigraphic Test Wells	2	2.0	-	-
Total:	2	2.0	141	117.0

See "*Principal Properties*" above for a description of Spartan's exploration and development plans.

Production Estimates

The following table sets forth the volume of Spartan's gross working interest production estimated for the year ending December 31, 2018, as evaluated by Sproule which is reflected in the estimate of future net revenue disclosed in the tables contained under "*Disclosure of Reserves Data and Other Information*".

	Light and Medium Crude Oil (Including C5+) ***(Bbls/d)***	**Heavy Crude Oil** ***(Bbls/d)***	**Conventional Natural Gas** ***(Mcf/d)***	**Natural Gas Liquids** ***(Bbls/d)***	**BOE** ***(BOE/D)***
Proved					
Alberta	205	-	60	-	215
Saskatchewan					
Southeast	18,544	-	12,411	1,225	21,838
West Central	1,368	-	-	-	1,368
Manitoba	159	-	-	-	159
Total Proved	20,276	-	12,471	1,225	23,580
Probable					
Alberta	39	-	11	-	41
Saskatchewan					
Southeast	2,267	-	2,137	186	2,810
West Central	262	-	-	-	262
Manitoba	12	-	-	-	12
Total Probable	2,581	-	2,148	186	3,125
Total Proved plus Probable	22,857	-	14,619	1,411	26,705

Production History

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

	2017 Quarter Ended				2017 Year Ended
	Q4 Dec. 31	**Q3 Sept. 30**	**Q2 June 30**	**Q1 March 31**	
Average Daily Production[(1)]					
Oil (Bbls/d)	19,620	19,742	19,511	19,231	19,528
Liquids (Bbls/d)	867	825	828	621	786
Gas (Mcf/d)	12,890	12,377	10,334	9,618	11,317
Combined (BOE/D)	22,635	22,630	22,061	21,455	22,200
Average Net Production Prices Received					
Oil ($/Bbl)	63.66	51.33	56.71	57.65	57.32
Liquids ($/Bbl)	33.67	27.69	28.11	26.85	29.30
Gas ($/Mcf)	2.53	2.18	3.07	3.05	2.67
Combined ($/BOE)	57.91	46.98	52.65	53.82	52.82
Royalties Paid					
Oil ($/Bbl)	10.06	8.63	9.60	9.07	8.21
Liquids ($/Bbl)	2.35	1.97	1.75	1.63	1.95
Gas ($/Mcf)	0.23	0.05	0.48	0.55	0.39
Combined ($/BOE)	8.94	7.80	8.78	8.42	8.49
Operating & Transportation Expenses					
Oil ($/Bbl)	17.09	18.46	19.60	18.42	18.39
Liquids ($/Bbl)	2.61	2.64	3.20	2.83	2.80
Gas ($/Mcf)	1.08	1.10	1.11	1.22	1.12
Combined ($/BOE)	16.02	17.28	18.47	17.56	17.32
Netback Received[(2)]					
Oil ($/Bbl)	36.51	24.25	27.51	30.16	30.72
Liquids ($/Bbl)	28.71	23.09	23.16	22.39	24.55
Gas ($/Mcf)	1.22	1.04	1.48	1.28	1.16
Combined ($/BOE)	32.95	21.90	25.40	27.84	27.01

Notes:

(1) Before deduction of royalties.

(2) Netback is calculated by deducting royalties paid and production costs, including transportation costs, from prices received.

The following table indicates Spartan's average daily production from its material properties for the year ended December 31, 2017:

	Oil (Bbls/d)	Liquids (Bbls/d)	Gas (Mcf/d)	BOE (BOE/D)
Saskatchewan				
Southeast	18,304	776	11,146	20,938
West Central	926	-	5	927
Alberta	177	10	166	214
Manitoba	121	-	-	121

Spartan's average production for the year ended December 31, 2017 was 92% liquids. For the year ended December 31, 2017, 97% of Spartan's gross revenue was derived from liquids production.

DIVIDEND POLICY

Spartan has not declared or paid any dividends on the Common Shares since incorporation. Any decision to pay dividends on the Common Shares will be made by the Board of Directors on the basis of Spartan's earnings, financial requirements and other conditions existing at such future time.

DESCRIPTION OF SHARE CAPITAL

Spartan is authorized to issue an unlimited number of Common Shares and an unlimited number of preferred shares, issuable in series (the "**Preferred Shares**").

As of December 31, 2017, an aggregate of approximately 176.6 million Common Shares were issued and outstanding, on a post-Consolidation basis. As at the date hereof, there are approximately 176.6 million Common Shares issued and outstanding. In addition, Spartan has approximately 10.1 million Warrants, approximately 3.3 million Options and approximately 2.2 million RSUs to acquire Common Shares outstanding as of the date hereof. There are no Preferred Shares issued or outstanding.

The holders of Common Shares are entitled to notice of and to vote at all meetings of shareholders (except meetings at which only holders of a specified class or series of shares are entitled to vote) and are entitled to one vote per Common Share. Holders of Common Shares are entitled to receive, if, as and when declared by the Board of Directors, such dividends as may be declared thereon by the Board of Directors from time to time. In the event of the liquidation, dissolution or winding-up of the Corporation, or any other distribution of assets among its shareholders for the purpose of winding-up its affairs, holders of Common Shares, are entitled to share equally, share for share, in the remaining property.

The Preferred Shares are issuable in series and each series of the Preferred Shares will have such rights, restrictions, conditions and limitations as the Board of Directors may from time to time determine. Holders of Preferred Shares are entitled, in priority to the holders of Common Shares, to receive, if, as and when declared by the Board of Directors, such dividends as may be declared thereon by the Board of Directors from time to time, to be paid ratably with the other holders of the Preferred Shares. In the event of the liquidation, dissolution or winding-up of the Corporation, or any other distribution of assets among its shareholders for the purpose of winding-up its affairs, holders of Preferred Shares are entitled, in priority to the holders of Common Shares, to share equally, share for share, in the property of the Corporation.

MARKET FOR SECURITIES

The Common Shares are listed on the TSX under the symbol "SPE". The following table sets the price range and trading volume of these securities for the period from January 1, 2017 to December 31, 2017, as reported by the TSX, adjusted to reflect the Consolidation:

	Common Shares		
Month	High	Low	Volume
January	$10.29	$8.19	17,729,257
February	$9.00	$7.98	19,931,324
March	$8.52	$6.87	25,988,994
April	$8.37	$6.45	16,403,173
May	$7.56	$6.12	18,862,379
June	$6.78	$5.52	20,542,954
July	$6.79	$5.70	18,740,398
August	$6.38	$5.03	30,201,392
September	$6.89	$5.60	26,074,686
October	$6.90	$5.75	19,567,943
November	$7.41	$6.35	24,612,553
December	$7.43	$6.40	13,956,465

DIRECTORS AND OFFICERS

The name, municipality of residence, shareholdings and principal occupation for the past 5 years of each of Spartan's directors and senior officers are as follows. The term of office for each director named below will expire at the next annual meeting of shareholders of Spartan.

Name	Positions Presently Held	Director Since	Principal Occupation for Previous Five Years
Richard F. McHardy *Calgary, Alberta*	Director, President and Chief Executive Officer	December 10, 2013	President and Chief Executive Officer of the Corporation since December 10, 2013. Prior to that, President and Chief Executive Officer of Spartan Oil Corp. from March 2011 to January 2013. Prior to that, President and Chief Executive Officer of Spartan Exploration Ltd., a public oil and gas exploration company, from January 2008 to June 2011.
Adam MacDonald *Calgary, Alberta*	Chief Financial Officer		Chief Financial Officer of the Corporation since February 24, 2016. Prior to that Interim Chief Financial Officer of the Corporation since August 14, 2014 and Controller of the Corporation since April 1, 2014. Prior to that, Controller of Renegade Petroleum Ltd. from October 2013 to April 2014 and Manager, Financial Reporting of Renegade Petroleum Ltd. from February 2011 to October 2013.
Fotis Kalantzis *Calgary, Alberta*	Senior Vice President, Exploration		Senior Vice President, Exploration of the Corporation since March 9, 2016 and Vice-President, Exploration of the Corporation from December 10, 2013 to March 9, 2016. Prior to that, Vice President, Operations of Spartan Oil Corp. from June 2011 to January 2013. Prior to that, Vice President, Operations of Spartan Exploration Ltd. from September 2010 to June 2011. Prior to that Vice President, Engineering and Operations of Spartan Exploration Ltd. from January 2008 to September 2010.

Name	Positions Presently Held	Director Since	Principal Occupation for Previous Five Years
Ed Wong *Calgary, Alberta*	Senior Vice President, Engineering		Senior Vice President, Engineering of the Corporation since March 9, 2016 and Vice President, Engineering of the Corporation from December 10, 2013 to March 9, 2016. Prior to that, Vice President, Engineering of Spartan Oil Corp. from June 2011 to January 2013. Prior to that Vice President, Engineering of Spartan Exploration Ltd. from September 2010 to June 2011. Prior to that Engineering Manager with Spartan Exploration Ltd. from September 2008 to September 2010.
Albert Stark *Calgary, Alberta*	Senior Vice President, Operations		Senior Vice President, Operations of the Corporation since March 9, 2016 and Vice President, Operations of the Corporation from December 10, 2013 to March 9, 2016. Prior to that, Vice President, Operations of Spartan Oil Corp. from June 2011 to January 2013. Prior to that Vice President, Operations of Spartan Exploration Ltd. from September 2010 to June 2011. Prior to that Vice President, Engineering and Operations of Spartan Exploration Ltd. from January 2008 to September 2010.
Randy Berg *Calgary, Alberta*	Vice President, Land		Vice President, Land of the Corporation since March 10, 2016. Prior to that Land Manager of the Corporation since April 1, 2014. Prior to that Vice President, Land and Business Development at Renegade Petroleum Ltd. from July 2012 to April 2014. Prior to that Conventional Business Unit Manager at Petrobakken Energy Ltd. from November 2010 to July 2012.
Michael J. Stark(1)(2) *Calgary, Alberta*	Chairman	December 10, 2013	Independent Businessman since 2006. Chairman of Spartan Oil Corp. from June 2011 to January 2013.
Reginald J. Greenslade(2)(3)(4) *Calgary, Alberta*	Director	December 10, 2013	Independent Businessman since February 2013. Director of Spartan Oil Corp. from June 2011 to January 2013. President and Director of Tuscany International Drilling Inc., an oilfield services company, from April 2010 to February 2013. Independent Businessman from March 2006 to April 2010.
Grant W. Greenslade(3)(4) *Shaunavon, Saskatchewan*	Director	December 10, 2013	Independent Businessman. Director of Spartan Oil Corp. from June 2011 to January 2013. President of Greenslade Consulting Ltd., a private oil and gas consulting company.
Donald Archibald(1)(2)(3) *Calgary, Alberta*	Director	December 10, 2013	Independent Businessman since March 2008. Director of Spartan Oil Corp. from June 2011 to January 2013.

Name	Positions Presently Held	Director Since	Principal Occupation for Previous Five Years
Sanjib Gill *Calgary, Alberta*	Corporate Secretary		Partner at the law firm of McCarthy Tétrault LLP since January 2008, practicing primarily in the areas of corporate finance, mergers and acquisitions.

Notes:
(1) Member of the Audit Committee.
(2) Member of the Compensation Committee.
(3) Member of the Corporate Governance Committee.
(4) Member of the Reserves and Environment Committee.

The directors and officers of Spartan, as a group, beneficially own, or exercise control or direction over, an aggregate of approximately 8.5 million Common Shares representing approximately 5% of the issued and outstanding Common Shares as of the date hereof.

The information as to Common Shares beneficially owned, directly or indirectly or over which control or direction is exercised, is based upon information furnished to Spartan by each of the individuals listed above.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

Except as set forth below, to the knowledge of management of Spartan:

(a) no director or executive officer is, or within the ten years prior to the date hereof has been, a director, chief executive officer or chief financial officer of any other issuer that, while that person was acting in that capacity: (i) was the subject of a cease trade order, an order similar to a cease trade order or an order that denied the relevant issuer access to any exemption under securities legislation for a period of more than 30 consecutive days; or (ii) was subject to a cease trade order, an order similar to a cease trade order or an order that denied the relevant issuer access to any exemptions under securities legislation that was issued after the director or 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;

(b) no director, executive officer or any shareholder holding a sufficient number of securities of the Corporation to affect materially the control of the Corporation, or a personal holding company of any such person: (i) is, or within the ten years prior to the date hereof has been, a director or executive officer that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; or (ii) has, within the 10 years preceding the date of this Annual Information Form, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or being 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 individual; and

(c) no director, executive officer or any shareholder holding a sufficient number of securities of the Corporation to affect materially the control of the Corporation, within the last 10 years, has: (i) been subject to any penalties or sanctions imposed by a court relating to Canadian securities legislation or by a Canadian securities regulatory authority or has entered into a settlement agreement with the Canadian securities regulatory authority; or (ii) been subject to 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.

Sanjib Gill was the Corporate Secretary of Action Energy Inc., a corporation engaged in the exploration, development and production of oil and gas in Western Canada. Action Energy Inc. was placed into receivership on October 28, 2009 by its major creditor and Mr. Gill resigned as the Corporate Secretary immediately thereafter.

Mr. Reginald Greenslade was a director of JMG Exploration, Inc. ("**JMG**"). On June 4, 2008, the Alberta Securities Commission issued a cease trade order in respect of JMG for failure to file audited annual financial statements for the year ended December 31, 2007 and interim financial statements for the period ended March 31, 2008. JMG filed audited annual financial statements for the years ended December 31, 2007 and December 31, 2008 on July 27, 2009. Mr. Greenslade resigned from the board of JMG in November 2009.

Mr. Archibald was a director of Waldron Energy Corporation ("**Waldron**") from December 31, 2009 to August 17, 2015. On August 6, 2015, the secured subordinated lender of Waldron demanded repayment in full of all amounts owed to it under its credit facility and gave notice of its intention to enforce its security. This repayment demand created a cross-default between Waldron and its secured bank lender, which subsequently demanded repayment in full of all amounts owed to it under its credit facility and also gave notice of its intention to enforce its security. After various discussions between Waldron and both its lenders, Waldron consented to the appointment of a receiver and manager on August 13, 2015. On August 17, 2015, a receiver and manager was appointed over the assets, undertakings and property of Waldron pursuant to an order of the Court of Queen's Bench of Alberta.

Conflicts of Interest

There are potential conflicts of interest to which the directors and officers of Spartan will be subject in connection with the operations of Spartan. In particular, certain of the directors and officers of Spartan are involved in managerial or director positions with other oil and gas companies, whose operations may, from time to time, be in direct competition with those of Spartan. Conflicts, if any, will be subject to the procedures and remedies available under the ABCA. The ABCA provides that, in the event that a director has an interest in a contract or a proposed contract or agreement, the director shall disclose his interest in such contract or agreement and shall refrain from voting on any matter in respect of such contract or agreement unless otherwise provided by the ABCA. As at the date of this Annual Information Form, Spartan is not aware of any existing or potential material conflicts of interest between Spartan and any director or officer of Spartan.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

To the knowledge of the Corporation, there are no legal proceedings or regulatory actions material to the Corporation to which the Corporation is a party, or was a party to in 2017, or of which any of its properties is the subject matter, or was the subject matter of in 2017, nor are there any such proceedings known to the Corporation to be contemplated. There have been no penalties or sanctions imposed against the Corporation by a court relating to securities legislation or by a securities regulatory authority and the Corporation has not entered to any settlement agreements with a court or securities regulatory authority.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Sanjib Gill, the Corporate Secretary of the Corporation, is a partner of the national law firm McCarthy Tétrault LLP, which law firm rendered legal services to the Corporation.

Other than as set out above, there are no material interests, direct or indirect, of directors or executive officers of Spartan, or any shareholder who beneficially owns, directly or indirectly, or exercises control or direction over more than 10% of the outstanding Common Shares, or any other Informed Person (as defined in National Instrument 51-102 *Continuous Disclosure Obligations* of the Canadian Securities Administrators) or any known associate or affiliate of such persons, in any transaction within the three most recently completed financial years or during the current financial that has materially affected or would materially affect Spartan or any of its subsidiaries.

AUDITOR, TRANSFER AGENT AND REGISTRAR

The auditor of the Corporation is PricewaterhouseCoopers LLP, Chartered Accountants at its office located at 3100, 111 – 5th Avenue S.W., Calgary, Alberta, T2P 5L3.

The transfer agent and registrar for the Common Shares is Alliance Trust Company at its office located at 1010, 407 - 2nd Street S.W., Calgary, Alberta, T2P 2Y3.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, the only material contract entered into by Spartan within the most recently completed financial year, or before the most recently completed financial year but which is still material and is in effect, which can reasonably be regarded as presently material, is the purchase and sale agreement in respect of the ARC Acquisition, which is available on the Corporation's SEDAR profile at *www.sedar.com*. See "*General Development of the Business – Three Year History*" above.

INTERESTS 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 Spartan during, or related to, Spartan's most recently completed financial year other than Sproule, the independent reserve evaluators, and PricewaterhouseCoopers LLP, Spartan's auditors.

None of the principals of Sproule had any registered or beneficial interests, direct or indirect, in any securities or other property of Spartan or of Spartan's associates or affiliates either at the time they prepared the statement, report or valuation prepared by it, at any time thereafter or to be received by them.

PricewaterhouseCoopers LLP is independent of Spartan in accordance with the rules of professional conduct of the Institute of Chartered Professional Accountants of Alberta.

Certain legal matters relating to the business of Spartan will be passed upon on Spartan's behalf by McCarthy Tétrault LLP. As at the date hereof, the partners and associates of McCarthy Tétrault LLP as a group beneficially own, directly or indirectly, less than 1% of the outstanding Common Shares.

AUDIT COMMITTEE

The purpose of Spartan's Audit Committee is to provide assistance to the Board of Directors in fulfilling its legal fiduciary obligations with respect to matters involving the accounting, auditing, financial reporting, internal control and legal compliance functions of the Corporation. It is the objective of the Audit Committee to maintain a free and open means of communications among the Board of Directors, the independent auditors and the financial and senior management of the Corporation.

The full text of the Audit Committee's Charter is included as Appendix "C" to this Annual Information Form.

Composition of the Audit Committee

As of the date hereof, the Audit Committee is comprised of:

Name of Director	Independent (Yes/No)[1]	Financially Literate (Yes/No)
Donald Archibald	Yes	Yes
Michael J. Stark	Yes	Yes
Grant Greenslade	Yes	Yes

Notes:
(1) As defined in NI 52-110.

Relevant Education and Experience

Collectively, the Audit Committee has the education and experience to fulfill the responsibilities outlined in the Audit Committee Charter. Mr. Archibald has held senior executive positions in oil and gas issuers and has participated as a member of audit committees in the past. Mr. Stark is a certified financial planner and previously served as the Chairman of the audit committee of Titan Exploration Ltd., Spartan Exploration Ltd. and Spartan Oil Corp. Mr. Greenslade is an independent businessman with many years of experience in the oil and gas industry.

Each member of the Audit Committee has: (i) an understanding of the accounting principles used by the Corporation to prepare its financial statements; (ii) the ability to assess the general application of those principles in connection with the estimates, accruals and reserves; (iii) experience in preparing, auditing, analyzing or evaluating financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of issues that can reasonably be expected to be raised by the Corporation's financial statements, or experience actively supervising individuals engaged in such activities; and (iv) an understanding of internal controls and procedures for financial reporting.

Reliance on Certain Exemptions

At no time since the commencement of the Corporation's most recently completed financial year has the Corporation relied on an exemption from NI 52-110, in whole or in part, granted under Part 8 of NI 52-110 (securities regulatory authority exemption).

Audit Committee Oversight

Since the commencement of Spartan's most recently completed financial year, there has not been a recommendation of the Audit Committee to nominate or compensate an external auditor which was not adopted by the Board of Directors.

Pre-Approval Policies and Procedures

The Audit Committee is authorized by the Board of Directors to review the performance of the Corporation's external auditors, and approve in advance the provision of services other than audit services and to consider the independence of the external auditors, including reviewing the range of services provided in the context of all consulting services bought by the Corporation. The Audit Committee is authorized to approve any non-audit services or additional work, which the Chairman of the Audit Committee deems as necessary.

External Auditor Service Fees

The fees paid to the Corporation's external auditor for audit services are as follows:

Financial Year Ending	Audit Fees [1]	Audit-Related Fees [2]	Tax Fees	All Other Fees
December 31, 2017	$288,000	$57,000	$Nil	$Nil

Notes:

(1) Audit fees consist of fees for the audit of annual consolidated financial statements or services that are normally provided in connection with statutory and regulatory filings or engagements. The services provided in this category include quarterly review fees.

(2) Audit-related fees consist of fees for assurance and related services that are reasonably related to the performance of the audit or review of the consolidated financial statements and are not reported as audit fees. The services provided in this category include auditing the transition to new accounting standards and the review of internal controls.

ADDITIONAL INFORMATION

Additional information, including directors' and officers' remuneration and indebtedness, principal holders of Common Shares and securities authorized for issuance under equity compensation plans, is contained in the Corporation's management information circular dated May 15, 2017.

Additional financial information is provided for in Spartan's financial statements and management's discussion and analysis for the year ended December 31, 2017. Documents affecting the rights of security holders, along with other information relating to the Corporation, may be found on SEDAR at www.sedar.com. Additional copies of this Annual Information Form and the materials listed in the preceding paragraph are available on the foregoing basis and upon request by contacting the Corporation at its offices at Suite 3200, 500 Centre Street SW, Calgary, Alberta, T2G 1A6, by phone at (403) 355-8920 or fax at (403) 355-2779.

APPENDIX A

REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

Terms to which a meaning is ascribed in National Instrument 51-101 have the same meaning herein.

To the board of directors of Spartan Energy Corp. (the "Corporation"):

1. We have evaluated of the Corporation's Reserves Data as at December 31, 2017. 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 Corporation'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 in the COGE Handbook.

5. The following table shows the net present value of future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Corporation evaluated for the year ended December 31, 2017, and identifies the respective portions thereof that we have evaluated and reported on to the Corporation's management and Board of Directors.

Independent Qualified Reserves Evaluator or Auditor	**Description and Preparation Date of Evaluation Report**	**Location of Reserves (Country)**	**Net Present Value of Future Net Revenue Before Income Taxes (10% Discount Rate)**			
			Audited (M$)	**Evaluated (M$)**	**Reviewed (M$)**	**Total (M$)**
Sproule	Evaluation of the P&NG Reserves of Spartan Energy Corp. As of December 31, 2017, dated February 20, 2018	Canada	**Nil**	**1,956,912**	**Nil**	**1,956,912**
Total			**Nil**	**1,956,912**	**Nil**	**1,956,912**

6. In our opinion, the reserves data evaluated by us have, in all material respects, been determined and are presented in accordance with the COGE Handbook. 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, entitled "Evaluation of the P&NG Reserves of Spartan Energy Corp. (As of December 31, 2017)".

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

Executed as to our report referred to above:

Sproule Associated Limited
Calgary, Alberta
March 14, 2018

(signed) "*Shishir Shivhare*"

Shishir Shivare, P.Eng.
Petroleum Engineer

(signed) "*Richard A. Brekke*"

Richard A Brekke, P.Eng.
Senior Manager, Engineering

(signed) "*Robert R. Warholm*"

Robert R. Warholm
Senior Manager, Quality and Assurance

(signed) "*Vincent K. Hui*"

Vincent K. Hui
Petroleum Engineer

(signed) "*Mykhailo Kyrylovych*"

Mykhailo Kyrylovych, P.Eng.
Petroleum Engineer

(signed) "*Michael Owens*"

Michael Owens, P.Tech.(Eng.), P.L.(Eng.)
Senior Technologist

(signed) "*Brian Trieber*"

Brian Trieber, P.L.(Geol.)
Senior Technologist

(signed) "*Maren Blair*"

Maren Blair, P.Geol.
Senior Geologist

(signed) "*Ian K. Kirkland*"

Ian K. Kirkland, P.Geol.
Senior Geologist

(signed) "*Alexander Minev*"

Alexander Minev, P.Geol.
Senior Geologist

(signed) "*Victor Verkhogliad*"

Victor Verkhogliad, P.Geol.
Manager, Geoscience

(signed) "Alec Kovaltchouk"

Alec Kovaltchouk, P.Geol.
VP, Geoscience

APPENDIX B

REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION

Terms to which a meaning is ascribed in National Instrument 51-101 have the same meaning herein.

Management of Spartan Energy Corp. (the “Corporation”) are responsible for the preparation and disclosure, or arranging for the preparation and disclosure of information with respect to the Corporation’s oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data.

Independent qualified reserves evaluators have evaluated and reviewed the Corporation’s reserves data. The report of the independent qualified reserves evaluators is presented in the Annual Information Form of the Corporation for the year ended December 31, 2017.

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

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

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

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

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

(a) the content and filing with securities regulatory authorities of From 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; 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.

(signed) “*Richard F. McHardy*”
Richard F. McHardy
President, Chief Executive Officer and a Director

(signed) “*Adam MacDonald*”
Adam MacDonald
Chief Financial Officer

(signed) “*Reginald J. Greenslade*”
Reginald J. Greenslade
Director

(signed) “*Michael J. Stark*”
Michael J. Stark
Director

Dated March 14, 2018

APPENDIX C

SPARTAN ENERGY CORP.
AUDIT COMMITTEE
TERMS OF REFERENCE

I. The Board of Directors' Mandate for the Audit Committee

A. The Board of Directors ("**Board**") has responsibility for the stewardship of Spartan Energy Corp. (the "**Corporation**"). To discharge that responsibility, the Board is obligated by the Business Corporations Act (Alberta) to supervise the management of the business and affairs of the Corporation. The Board's supervisory function involves Board oversight or monitoring of all significant aspects of the management of the Corporation's business and affairs.

Public financial reporting and disclosure by the Corporation are fundamental to the Corporation's business and affairs. The objective of the Board's monitoring of the Corporation's financial reporting and disclosure is to gain reasonable assurance of the following:

1) that the Corporation complies with all applicable laws, regulations, rules, policies and other requirement of governments, regulatory agencies and stock exchanges, if applicable, relating to financial reporting and disclosure;

2) that the accounting principles, significant judgements and disclosures which underlie or are incorporated in the Corporation's financial statements are appropriate in the prevailing circumstances;

3) that the Corporation's quarterly and annual financial statements are accurate within a reasonable level of materiality and present fairly the Corporation's financial position and performance in accordance with generally accepted accounting principles; and

4) that appropriate information concerning the financial position and performance of the Corporation is disseminated to the public, to the extent required by applicable securities laws, in a timely manner in accordance with corporate and securities law and with stock exchange regulations, if applicable.

The Board is of the view that monitoring of the Corporation's financial reporting and disclosure policies and procedures cannot be reliably met unless the following activities (the "Fundamental Activities") are, in all material respects, conducted effectively:

1) the Corporation's accounting functions are performed in accordance with a system of internal financial controls designed to capture and record properly and accurately all of the Corporation's financial transactions and consistent with internal financial controls implemented by companies of similar size and peer group as the Corporation;

2) the internal financial controls are regularly assessed for effectiveness and efficiency consistent with assessments performed by companies of similar size and peer group as the Corporation;

3) the Corporation's quarterly and annual financial statements are properly prepared by management to comply with International Financial Reporting Standards ("IFRS");

4) the Corporation's quarterly and annual financial statements are reported on by an external auditor appointed by the shareholders of the Corporation.

To assist the Board in its monitoring of the Corporation's financial reporting and disclosure and to conform to applicable corporate and securities law, the Board has established the Audit Committee (the "Committee") of the Board.

B. Composition of Committee

1) The Committee shall be appointed annually by the Board and consist of at least three members from among the directors of the Corporation, each of whom shall be an independent director (as determined under applicable laws). Officers of the Corporation, who are also directors, may not serve as members of the Committee;

2) The Board shall designate the Chairman of the Committee; and

3) In the event of a vacancy arising in the Committee or a loss of independence of any member, the Committee will fill the vacancy within six months or by the following annual shareholders' meeting if sooner.

C. Reliance on Experts

In contributing to the Committee's discharging of its duties under this mandate, each member of the Committee shall be entitled to rely in good faith upon:

1) financial statements of the Corporation represented to him by an officer of the Corporation or in a written report of the external auditors to present fairly the financial position of the Corporation in accordance with generally accepted accounting principles; and

2) any report of a lawyer, accountant, engineer, appraiser or other person whose profession lends credibility to a statement made by any such person.

D. Limitations on Committee's Duties

In contributing to the Committee's discharging of its duties under Terms of Reference, each member of the Corporation shall be obliged only to exercise the care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances. Nothing in these Terms of Reference is intended, or may be construed, to impose on any member of the Committee a standard of care or diligence that is in any way more onerous or extensive than the standard to which all Board members are subject. The essence of the Committee's duties is monitoring and reviewing to endeavor to gain reasonable assurance (but not to ensure) that the Fundamental Activities are being conducted effectively and that the objectives of the Corporation's financial reporting are being met and to enable the Committee to report thereon to the Board.

II. Audit Committee Terms of Reference

The Committee's Terms of Reference outlines how the Committee will satisfy the requirements set forth by the Board in its mandate. Terms of Reference reflect the following:

- Operating Principles;
- Operating Procedures;
- Specific Responsibilities and Duties.

A. Operating Principles

The Committee shall fulfill its responsibilities within the context of the following principles:

1) Committee Values

The Committee expects the management of the Corporation to operate in compliance with corporate policies; reflecting laws and regulations governing the Corporation; and to maintain strong financial reporting and control processes.

2) Communications

The Committee and members of the Committee expect to have direct, open and frank communications throughout the year with management, other Committee Chairmen, the external auditors, and other key Committee advisors or Corporation staff members as applicable.

3) Financial Literacy

All Committee Members should be sufficiently versed in financial matters to read and understand the Corporation's financial statements and also to understand the Corporation's accounting practices and policies and the major judgements involved in preparing the financial statements.

4) Annual Audit Committee Work Plan

The Committee, in consultation with management and the external auditors, shall develop an annual Committee work plan responsive to the Committee's responsibilities as set out in these Terms of Reference. In addition, the Committee, in consultation with management and the external auditors, shall participate in a process for review of important financial topics that have the potential to impact the Corporation's financial disclosure.

The work plan will be focused primarily on the annual and interim financial statements of the Corporation; however, the Committee may at its sole discretion, or the discretion of the Board, review such other matters as may be necessary to satisfy the Committee's Terms of Reference.

5) Meeting Agenda

Committee meeting agendas shall be the responsibility of the Chairman of the Committee in consultation with Committee members, senior management and the external auditors.

6) Committee Expectations and Information Needs

The Committee shall communicate its expectations to management and the external auditors with respect to the nature, timing and extent of its information needs. The Committee expects that written materials will be received from management and the external auditors at a reasonable time in advance of meeting dates.

7) External Resources

To assist the Committee in discharging its responsibilities, the Committee may at its discretion, in addition to the external auditors, at the expense of the Corporation, retain one or more persons having special expertise, including independent counsel.

8) In Camera Meetings

At the discretion of the Committee, the members of the Committee shall meet in private session with the external auditors. In addition, at the discretion of the Committee, the members of the Committee shall meet in private with the management of the Corporation, without the auditors being present at such meeting.

9) Reporting to the Board

The Committee, through its Chairman, shall report after each Committee meeting to the Board at the Board's next regular meeting.

10) Committee Self Assessment

The Committee shall annually review, discuss and assess its own performance. In addition, the Committee shall periodically review its role and responsibilities.

11) The External Auditors

The Committee expects that, in discharging their responsibilities to the shareholders, the external auditors shall report directly to and be accountable to the Board through the Committee. The external auditors shall report all material issues or potentially material issues, either specific to the Corporation or to the financial reporting environment in general, to the Committee.

B. Operating Procedures

1) The Committee shall meet at least four times annually, or more frequently as circumstances dictate. Meetings shall be held at the call of the Chairman, upon the request of two members of the Committee or at the request of the external auditors.

2) A quorum shall be a majority of the members.

3) Unless the Committee otherwise specifies, the Secretary (or his or her deputy) of the Corporation shall act as Secretary of all meetings of the Committee.

4) In the absence of the Chairman of the Committee, the members shall appoint an acting Chairman.

5) A copy of the minutes of each meeting of the Committee shall be provided to each member of the Committee and to each director of the Corporation in a timely fashion.

C. Specific Responsibilities and Duties

To fulfill its responsibilities and duties, the Committee shall:

1) Financial Reporting

(a) Review, prior to public release, the Corporation's annual and quarterly financial statements with management and the external auditors with a view to gaining reasonable assurance that the statements (i) are accurate within reasonable levels of materiality, (ii) complete, (iii) represent fairly the Corporation's financial position and performance in accordance with IFRS. The Committee shall report thereon to the Board before such financial statements are approved by the Board;

(b) Receive from the external auditors reports of their review of the annual and quarterly financial statements and any management letters issued to the management of the Corporation;

(c) Receive from management a copy of the representation letter provided to the external auditors and receive from management any additional representations required by the Committee;

(d) Review, prior to public release, to the extent required pursuant to applicable securities laws, and, if appropriate, recommend approval to the Board, of news releases, to the extent required pursuant to applicable securities laws, and reports to shareholders issued by the Corporation with respect to the Corporation's annual and quarterly financial statements;

(e) Review and, if appropriate, recommend approval to the Board of prospectuses, material change disclosures of a financial nature, management discussion and analysis, annual information forms and similar disclosure documents that may be issued by the Corporation; and

(f) Review and validate procedures for the receipt, retention and resolution of complaints received by the Corporation from any party regarding accounting, auditing or internal controls. For greater certainty, the Committee's responsibilities in this area will not include complaints about minor operational issues. (Examples of minor operational issues include late payment of invoices, minor disputes over accounts owing or receivable, revenue and expense allocations and other similar items characteristic of the normal daily operations of the accounting department of an oil and gas company.)

2) Accounting Policies

(a) Review with management and the external auditors the appropriateness of the Corporation's accounting policies, disclosures, reserves, key estimates and judgements, including changes or variations thereto.

(b) Obtain reasonable assurance that they are in compliance with IFRS from management and external auditors and report thereon to the Board.

(c) Review with management and the external auditors the apparent degree of conservatism of the Corporation's underlying accounting policies, key estimates and judgements and provisions along with quality of financial reporting.

(d) Participate, if requested, in the resolution of disagreements, between management and the external auditors.

(e) Review with management the categorization of flow through expenditures and the qualification of such expenditures to satisfy the Corporation's existing obligations.

3) Risk and Uncertainty

(a) Acknowledging that it is the responsibility of the Board, in consultation with management, to identify the principal business risks facing the Corporation, determine the Corporation's tolerance for risk and approve risk management policies, the Committee shall focus on financial risk and gain reasonable assurance that financial risk is being effectively managed or controlled by:

(i) reviewing with management the Corporation's tolerance for financial risks;

(ii) reviewing with management its assessment of the significant financial risks facing the Corporation;

(iii) reviewing with management the Corporation's policies and any proposed changes thereto for managing those significant financial risks;

(iv) reviewing with management its plans, processes and programs to manage and control such risks;

(b) Review policies and compliance therewith that require significant actual or potential liabilities, contingent or otherwise, to be reported to the Board in a timely fashion;

(c) Review foreign currency, interest rate and commodity price risk mitigation strategies, including the use of derivative financial instruments;

(d) Review the adequacy of insurance coverages maintained by the Corporation;

(e) Review regularly with management, the external auditors and the Corporation's legal counsel, any legal claim or other contingency, including tax assessments, that could have a material effect upon the financial position or operating results of the Corporation and the manner in which these matters have been disclosed in the financial statements.

4) Financial Controls and Control Deviations

(a) Review the plans of the external auditors to gain reasonable assurance that the evaluation and testing of applicable internal financial controls is comprehensive, coordinated and cost effective;

(b) Receive regular reports from management and the external auditors on all significant deviations or indications/detection of fraud and the corrective activity undertaken in respect thereto;

(c) Institute a procedure that will permit any employee, including management employees, to bring to the attention of the Chairman of the Committee, under conditions of confidentiality, concerns relating to financial controls and reporting which are material in scope and which cannot be addressed, in the employee's judgement, through existing reporting structures in the Corporation;

(d) Review, and periodically assess the adequacy of controls over financial information disclosed to the public, which is extracted or derived from the Corporation's financial statements.

5) Compliance with Laws and Regulations

(a) Review regular reports from management and others (e.g. external auditors) with respect to the Corporation's compliance with laws and regulations having a material impact on the financial statements including:

(i) tax and financial reporting laws and regulations;

(ii) legal withholding requirements;

(iii) other laws and regulations which expose directors to liability;

(b) Review the filing status of the Corporation's tax returns, flow through share renunciation filings and those of its subsidiaries.

6) Relationship with External Auditors

(a) Recommend to the Board the nomination of the external auditors;

(b) Approve the remuneration and the terms of engagement of the external auditors as set forth in the Engagement Letter;

(c) Review the performance of the external auditors annually or more frequently as required;

(d) Receive annually from the external auditors an acknowledgement in writing that the shareholders, as represented by the Board and the Committee, are their primary client;

(e) Receive a report annually from the external auditors with respect to their independence, such report to include a disclosure of all engagements (and fees related thereto) for non audit services by the Corporation;

(f) Review with the external auditors the scope of the audit, the areas of special emphasis to be addressed in the audit, and the materiality levels which the external auditors propose to employ;

(g) Meet with the external auditors in the absence of management to determine, inter alia, that no management restrictions have been placed on the scope and extent of the audit examinations by the external auditors or the reporting of their findings to the Committee;

(h) Establish effective communication processes with management and the Corporation's external auditors to assist the Committee to monitor objectively the quality and effectiveness of the relationship among the external auditors, management and the Committee; and

(i) Establish a reporting relationship between the external auditors and the Committee such that the external auditors can bring directly to the Committee matters that, in the judgement of the external auditors, merit the Committee's attention. In particular, the external auditors will advise the Committee as to disagreements between management and the external auditors regarding financial reporting and how such disagreements were resolved.

7) Other Responsibilities

(a) Approve annually the reasonableness of the expenses of the Chairman of the Board and the Chief Executive Officer;

(b) After consultation with the Chief Financial Officer and the external auditors, consider at least annually the quality and sufficiency of the Corporation's accounting and financial personnel and other resources;

(c) Approve in advance non-audit services, including tax advisory and compliance services, provided by the external auditors. However, the Committee can establish a threshold amount for fees for non-audit services to be provided by the external auditors without advance approval of the Committee. In such case, the nature of such services and the associated cost will be provided to the Committee at the next following meeting;

(d) Investigate any matters that, in the Committee's discretion, fall within the Committee's duties;

(e) Perform such other functions as may from time to time be assigned to the Committee by the Board;

(f) Review and update the Terms of Reference on a regular basis for approval by the Board; and

(g) The Committee will review disclosures regarding the organization and duties of the Committee to be included in any public document, including quarterly and annual reports to shareholders, information circulars and annual information forms.