Annual Information Form
Financial Year Ended December 31, 2013

Dated April 30, 2014

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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, 2013, 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
Mbbls	thousand barrels	Mmcf/d	million cubic feet per day
Mmbbls	million barrels	MMBTU	million British Thermal Units
Mstb	1,000 stock tank barrels	Bcf	billion cubic feet
Bbls/d	barrels per day	GJ	Gigajoule
NGLs	natural gas liquids		
STB	Standard tank barrels		

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.
ARTC	Alberta Royalty Tax Credit
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
m3	cubic metres
EPEA	*Environmental Protection and Enhancement Act* (Alberta)
MBOE	1,000 barrels of oil equivalent
OOIP	original oil in place
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 prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society), as amended from time to time;

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

"**Corporation**" or "**Spartan**" means Spartan Energy Corp.;

"**Flow-Through Shares**" means Common Shares issued on a "flow-through" basis as defined in the Tax Act;

"**Lender**" means the National Bank of Canada;

"**McDaniel**" means McDaniel & Associates Consultants Ltd.;

"**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*;

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

"**Renegade**" means Renegade Petroleum Ltd.;

"**Sproule**" means Sproule Associates Limited;

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

"**TSXV**" means the TSX Venture Exchange; and

"**U.S.**", "**US**" or "**United States**" means the United States of America.

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, net revenue, future production levels, projection of market prices, capital expenditures, exploration plans, development plans, acquisition and disposition plans and the timing thereof, operating and other costs, world-wide supply and demand for petroleum products, royalty rates and treatment under governmental regulatory regimes. In addition, this Annual Information Form may contain forward-looking statements attributed to third party industry sources.

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

- future development and growth prospects;
- ability to meet current and future obligations;
- treatment under governmental regulatory regimes and tax laws;
- the ability to obtain financing on acceptable terms or at all; and
- currency, exchange and interest rates.

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;
- the risks of the oil and gas industry, such as operational risks and market demand;
- governmental regulation of the oil and gas industry, including environmental regulation;
- 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;
- general economic and business conditions;
- 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;
- uncertainty in amounts and timing of royalty payments;
- 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. Except as required by applicable securities laws, the Corporation does not undertake any obligation to publicly update or revise any forward-looking statements and readers should also carefully consider the matters discussed under the heading "*Risk Factors*" below.

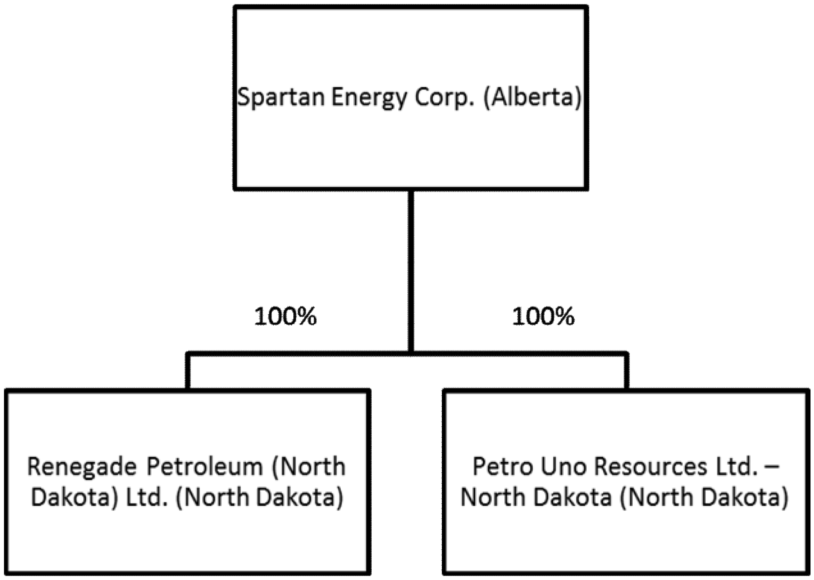
The forward-looking statements or information contained herein are made as of the date hereof and the Corporation undertakes no obligation to update or revise any forward looking statements, whether as a result of new information, future events or otherwise, unless required by applicable securities laws.

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.".

Spartan's head office is located at Suite 500, 850- 2nd Street SW, Calgary, Alberta T2P 0R8, and the registered office is located at Suite 4000, 421 – 7th Avenue, S.W., Calgary, Alberta, T2P 4K9.

As at December 31, 2013, the Corporation had no material subsidiaries. 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 and Ontario. The Common Shares are listed on the TSXV under the trading symbol "SPE".

GENERAL DEVELOPMENT OF THE BUSINESS

Financial Year Ended December 31, 2011

On January 11, 2011, the Corporation announced that it was drilling an oil development location at Alexander, Alberta. After drilling the well to total depth identifying three to four hydrocarbon zones, the drilling equipment became stuck in the hole. In February, after several attempts to remove the equipment, the Corporation had decided to abandon the well.

On March 3, 2011, the Corporation announced that it had acquired additional lands with a 94% working interest directly offsetting its development lands in the Alexander area of Alberta.

On April 8, 2011, the Corporation announced that it had successfully drilled an exploration well at Goose River, Alberta. At Alexander, Alberta, the Corporation drilled and cased two wells targeting oil with the two wells to be tied-in after spring break-up.

On May 26, 2011, the Corporation announced that it received regulatory approval to tie-in a well at 8-7-56-26W4, which well was placed on stream May 1, 2011. The Corporation has a 100% working interest in the well. The Corporation also licensed and drilled two wells before the spring break-up targeting the same Detrital oil zone. One of the wells is a twin well to a well abandoned at 00/10-7-56-26W4M. The second well at 13-7-56-26W4M was perforated and tested. The Corporation has a 79% interest in these two wells.

On June 9, 2011, the Corporation announced the completion of the testing of two wells at Alexander, Alberta, one in the Calahoo zone with a 94% working interest and one in the Detrital zone with a 79% working interest.

On July 7, 2011, the Corporation announced the completion and fracturing of the 102/10-7-56-26W4 well in the Alexander sand zone in which the Corporation has a 79% working interest.

On August 19, 2011, the Corporation closed a private placement offering of Flow-Through Shares at a price of $0.40 per Flow-Through Share, for gross proceeds of $2.4 million. Emerging Equities Inc. acted as agent for the private placement and received a commission equal to 6% of the gross proceeds from the private placement and 358,680 broker warrants, each broker warrant entitling the holder to purchase one Common Share at $0.40 per share until August 19, 2012.

On October 4, 2011, the Corporation announced the formation of a special committee of the Board of Directors, comprised of Gary Van Nest, as chair, and fellow directors Allan Rasmuson and Peter Lubey to review strategic options available to the Corporation on a go-forward basis, with the view toward maximizing shareholder value. In this regard, the Corporation retained the services of Emerging Equities Inc. to act as financial advisor in this process.

On November 24, 2011, the Corporation announced the tie-in of its 09-12-56-27W4 step-out well producing from the Detrital oil zone which came on stream on October 26, 2011 and a 12% increase in proved plus probable reserves based on an independent reserves evaluation prepared by McDaniel effective October 1, 2011.

On December 19, 2011, the Corporation announced that a letter of intent it had entered into with a private company regarding a proposed recapitalization and change of management of the Corporation was terminated as the private company failed to secure financing.

Financial Year Ended December 31, 2012

On March 27, 2012, the Corporation announced that it had cased its 11-12-56-27W4 well, which was subsequently completed and brought on stream. Spartan is the operator and has a 94% working interest in the well.

On September 9, 2012, the Corporation changed its name to “Alexander Energy Ltd.”. The Corporation’s Common Shares began trading on the TSXV under the new symbol “ALX”.

On October 23, 2012, the Corporation announced that it had received approval from the Lender for a revolving operating demand loan of $12 million and a development demand loan of $3.5 million. The Lender also approved a $1.1 million drawdown on the development demand loan to drill, complete, tie-in and equip the 15-12-56-27W4 well.

On October 25, 2012, the Corporation announced the spudding of a well at 15-12-56-27W4. On October 30, 2012, the Corporation announced that it had cased the 15-12-56-27W4 development well, in which Spartan has a 94% working interest, as a potential Detrital sand oil well. As a northerly step-out well to two producing oil wells in the Corporation’s Detrital C oilpool, this well was the Corporation’s sixth consecutive successful oil well in the pool. This result set up several more development locations to the west and further to the north, all on lands controlled by the Corporation. On November 19, 2012, the Corporation announced the completion and testing of the 15-12-56-27W4 well.

Financial Year Ended December 31, 2013

Effective March 20, 2013, the Corporation renewed its credit facilities with the Lender, consisting of Facility A, a revolving operating demand loan with a maximum limit of $13 million and Facility, a non-revolving acquisition/development demand loan that provides an additional $2.5 million of financing subject to bank approval. On March 20, 2013 the Corporation drew down the non-revolving acquisition/development demand loan in the amount of $1.2 million.

On April 3, 2013, the Corporation announced that it had perforated and tested its recently drilled 7-7-56-26W4 well in the Detrital oil zone. Also, the Corporation had drilled and cased a second well at 12-12-56-27W4 as a potential Detrital oil well. The 7-7-56-26W4 well was put on production in April, 2013 and the 12-12-56-27W4 well was put on production in June, 2013.

On September 13, 2013, the Corporation announced the completion of a private placement of Common Shares at a price of $0.15 per share, for gross proceeds of $1.3 million.

On December 5, 2013, the Corporation entered into a reorganization and investment agreement (the "**Reorganization Agreement**") with Richard F. McHardy, Michelle Wiggins, Fotis Kalantzis, Ed Wong, Albert Stark and Thomas Boreen, which provided for: (i) a non-brokered private placement of up to an aggregate of approximately $26.5 million (the "**Recapitalization Transaction**"); (ii) the appointment of a new management team (the "**New Management Team**") and a new Board of Directors (the "**New Board**"); and (iii) a rights offering to current holders of Common Shares (the "**Rights Offering**"). The New Management Team was led by Richard F. McHardy as President & Chief Executive Officer, Michelle Wiggins as Vice President, Finance and Chief Financial Officer, Fotis Kalantzis as Vice President, Exploration, Ed Wong as Vice President, Engineering, Albert Stark as Vice President, Operations and Thomas Boreen as Vice President, Geology. The New Board was comprised of Richard F. McHardy, Michael Stark, Reginald Greenslade, Grant Greenslade and Don Archibald. Sanjib Gill was appointed Corporate Secretary.

On December 10, 2013, the New Management Team and New Board were appointed. The Corporation also issued a total of 119,735,183 units ("**Units**") at a price of $0.15 per Unit, for aggregate proceeds of approximately $18 million (the "**Initial Closing**"). The Units issued under the Initial Closing were issued to the New Management Team, the New Board and certain other individuals identified by the New Management Team and the New Board. Each Unit was comprised of one Common Share and one Common Share purchase warrant ("**Warrant**"), each Warrant entitling the holder thereof to purchase one Common Share at a price of $0.20 for a period of five years. On January 9, 2014, all of the vesting thresholds were met and the Warrants became fully vested and exercisable.

On December 17, 2013, the Corporation entered into a definitive purchase and sale agreement to acquire a crude oil producing asset (the "**Spartan Acquired Assets**") located in southeast Saskatchewan (the "**Asset Acquisition**") for $32.5 million, subject to normal closing adjustments. On February 3, 2014, the Corporation completed the Asset Acquisition.

On December 18, 2013, concurrent with the announcement of the Asset Acquisition, the Corporation commenced a private placement offering, on a bought-deal basis (the "**Financing**"), of special warrants ("**Special Warrants**"), which was subsequently upsized for aggregate gross proceeds of approximately $75 million. Each Special Warrant entitled the holder thereof, without additional consideration or action on the part of the holder, to one Common Share upon the occurrence of certain events.

The Recapitalization Transaction was completed on December 24, 2013, with the Corporation issuing 15,151,668 Units at a price of $0.15 per unit and an aggregate of 41,779,816 Common Shares at a price of $0.15 per Common Share for aggregate proceeds of approximately $8.6 million. As a result of this closing and the Initial Closing, a total of 176,666,667 Common Shares (44,166,672 on a post-consolidation basis) and 134,886,851 Warrants (33,721,718 on a post-consolidation basis) were issued for total gross proceeds of approximately $26.5 million.

Recent Developments

On January 13, 2014, the Corporation completed the Financing and issued 153,062,000 Special Warrants at a price of $0.49 per Special Warrant for aggregate proceeds of $75,000,380, which Special Warrants converted into Common Shares on February 19, 2014 upon the filing of a final prospectus. On January 13, 2014, the Corporation also closed a private placement offering of 5,100,000 Common Shares at a price of $0.49 per Common Share for gross proceeds of approximately $2.5 million.

On February 10, 2014, the Corporation entered into an arrangement agreement with Renegade whereby the Corporation agreed to acquire all of the issued and outstanding shares of Renegade in exchange for 2.25

Common Shares (0.5625 Common Shares on a post-consolidation basis) for each share of Renegade. Pursuant to the Arrangement, the Corporation would acquire approximately 5,200 bbls per day (96.6% oil and liquids) of primarily southeast and west central Saskatchewan assets, including key producing infrastructure such as batteries, pipelines and waterflood facilities. These assets of Renegade include an average working interest of approximately 85% in 150,571 net acres of undeveloped land as at December 31, 2013.

On February 18, 2014, the Corporation held a special meeting of Shareholders where shareholders considered and approved changing the corporate name from "Alexander Energy Ltd." to "Spartan Energy Corp." and a share consolidation on the basis of one post-consolidation Common Share for every four pre-consolidation Common Shares. The name change and share consolidation became effective on February 28, 2014 and the Corporation's Common Shares began trading on the TSXV under the new name "Spartan Energy Corp." and stock symbol "SPE".

On March 19, 2014, the Corporation completed the Rights Offering with the issuance of 2,153,633 Common Shares at a price of $0.60 per Common Share resulting in aggregate gross proceeds of $1.3 million.

On March 31, 2014, Spartan closed the Arrangement for total consideration of approximately $495 million, comprised of 117,520,001 Common Shares, on a post-consolidation basis, and assumed debt of approximately $168 million. Pursuant to the Arrangement, Thomas Budd, a former director of Renegade, was appointed as an independent director to the Board of Directors.

NARRATIVE DESCRIPTION OF THE BUSINESS

General

Spartan is focussed on predominately light and medium oil opportunities in Saskatchewan and Alberta, growing through development and exploration drilling. Spartan's extensive opportunity base and current oil weighted production base (93% 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.

As part of its continued 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 and Alberta 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.

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.

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.

Spartan's geographically focused business expansion has positioned it to benefit from currently prevailing favourable industry conditions. Since commencing active oil and gas operations upon completion of the Recapitalization Transaction, 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 the Asset Acquisition and the Arrangement, combined with the ability to execute strategic corporate and property acquisitions, is expected to continue to support and expand its existing asset base.

Personnel

As at the date hereof, Spartan has 57 full time employees.

Industry Conditions

Canadian Government Regulation

The oil and gas industry is subject to extensive controls and regulations imposed by various levels of government and, with respect to pricing and taxation of oil and 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 - Oil

In Canada, producers of oil negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. The price depends in part on oil type and quality, prices of competing fuels, distance to market, the value of refined products and the supply/demand balance. Oil exports may be made pursuant to export contracts with terms not exceeding one year in the case of light crude, and not exceeding two years in the case of heavy crude, provided that an order approving any such export has been obtained from the NEB. Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export licence from the NEB and the issuance of such a licence requires the approval of the Governor in Council.

Pricing and Marketing - Natural Gas

In Canada, the price of natural gas sold in interprovincial and international trade is determined by negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain criteria prescribed by the NEB and the Government of Canada. Natural gas exports for a term of less than two years or for a term of 2 to 20 years (in quantities of not more than 30,000 m^3/day), must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or a larger quantity requires an exporter to obtain an export licence from the NEB and the issue of such a licence requires the approval of the Governor in Council.

The governments of Saskatchewan, Alberta and Manitoba regulate the volume of natural gas which may be removed from those provinces for consumption elsewhere based on such factors as reserve availability, transportation arrangements and market considerations.

Pipeline Capacity

Western Canada has seen significant growth in crude production volumes over recent years. This has resulted in pressure on the pipeline take-away capacity, leading to apportionment on the main lines and, in turn, backed-up local feeder pipelines. This has contributed to a widening of, and increased volatility in, the light oil pricing differential between WTI and Edmonton Par and the medium/heavy oil pricing differential between WTI and Cromer/WCS/Hardisty. Although pipeline expansions are ongoing and producers are increasingly turning to rail as an alternative means of transportation, the lack of firm pipeline capacity continues to affect the oil and gas industry and limit the ability to produce and to market production. In addition, the pro-rationing of capacity on the interprovincial systems also continues to affect the ability to export oil and natural gas.

Availability of Services

The availability of the services necessary to drill and complete the types of horizontal oil wells that form a substantial portion of the Corporation's planned exploration and development activities in 2013 and 2014 remains constrained due to increased demand and competition for such services. Spartan does not anticipate that, at current commodity prices, such constraint will be alleviated in the near future.

The North American Free Trade Agreement

On January 1, 1994, NAFTA became effective among the governments of Canada, the United States and Mexico. NAFTA carries forward most of the material energy terms contained in the Canada-U.S. Free Trade Agreement. In the context of energy resources, Canada continues to remain free to determine whether exports to the United States or Mexico will be allowed provided that any export restrictions do not: (i) reduce the proportion of energy resource exported relative to domestic use (based upon the proportion prevailing in the most recent 36 month period); (ii) impose an export price higher than the domestic price; or (iii) disrupt normal channels of supply. All three countries are prohibited from imposing minimum export or import price requirements.

NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector and prohibits discriminatory border restrictions and export taxes. NAFTA also contemplates clearer disciplines on regulators to ensure fair implementation of any regulatory changes and to minimize disruption of contractual arrangements, which is important for Canadian exports.

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

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 by improving earnings and cash flow within the industry. Royalty holidays and reductions would reduce the amount of Crown royalties paid by oil and natural gas producers to the provincial governments and would increase the net income and funds from operations of such producers. However, the trend in recent years has been for provincial governments to allow such incentive programs to expire without renewal, and consequently few such incentive programs are currently operative.

Saskatchewan Royalties

With respect to production obtained from Crown lands in the Province of Saskatchewan, the amount payable as a royalty in respect of crude oil depends on the vintage of the oil, the type of oil, the quantity of oil produced in a month, and the price of the oil. For both Crown royalty and freehold production tax purposes, crude oil is categorized by oil type as either "heavy oil", "southwest designated oil", or "non-heavy oil other than southwest designated oil". Additionally, the oil in each category is subdivided according to the conventional royalty and production tax classifications as either "fourth tier oil", "third tier oil", "new oil", or "old oil". Depending on the categorization and classification of the oil, monthly production, and a prescribed reference price determined monthly by the Saskatchewan Ministry of Energy and Resources ("**SER**"), the royalty reserved to the Crown ranges from 0% to 45%.

Similarly, the amount payable as a royalty in respect of natural gas in the Province of Saskatchewan depends on the vintage of the gas, the type of gas production, the quantity of gas produced in a month, and the price of the gas. For both Crown royalty and freehold production tax purposes, natural gas is categorized as either non-associated gas or associated gas, the former being produced from gas wells and the latter being produced from oil wells. Additionally, the gas is divided according to the royalty and production tax classifications as either "fourth tier gas", "third tier gas", "new gas", or "old gas". Depending on the categorization and classification of the natural gas, monthly production, and a reference price, the royalty reserved to the Crown ranges from 0% to 45%. Subject to certain restrictions, the operator may elect to use either a prescribed reference price determined monthly by SER, or a reference price based on the operator's average gas price in a month. As an incentive for the production and marketing of natural gas which may have been flared, the royalty rate on associated gas is less than on non-associated natural gas.

Approximately one-fifth of the mineral rights in the Province of Saskatchewan are freehold mineral rights not owned by the Crown. With respect to production from lands other than Crown lands, the tax levied in respect of freehold oil and gas production in the Province of Saskatchewan is determined by reducing the Crown royalty rate that would otherwise be payable if the lands were Crown lands by a fixed amount. Currently, this reduction ranges from 6.9% to 12.5% depending on the classification of the oil or gas.

Saskatchewan Incentives

The Government of Saskatchewan currently provides a number of targeted incentive programs. These include both royalty reduction and incentive volume programs.

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 m3 for deep development vertical oil wells, 4,000 m3 for non-deep exploratory vertical oil wells and 16,000 m3 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 m3 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 rates on incentive volumes of 6,000 m3 for non-deep horizontal oil wells and 16,000 m3 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 m3 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.

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

Alberta Royalties

In terms of oil or natural gas production from Crown lands in the Province of Alberta, royalties are payable to the Province of Alberta. On October 25, 2007, the Government of Alberta unveiled a new royalty regime for determining Crown royalty rates in Alberta (the "**Royalty Framework**"), effective January 1, 2009, intended to ensure that Albertans receive a fair share from energy development through royalties, taxes and fees. The new Royalty Framework introduced new royalties applicable to all conventional oil and natural gas wells and bitumen production, with the exception of those subject to the transitional royalty rate discussed below.

The new Royalty Framework eliminated the previous tier system for conventional oil, which was based on the vintage or discovery date of the oil, and implemented a sliding rate formula based on both the commodity price of oil and well production. Subject to certain available incentives, effective from the January 2011 production month royalty rates for conventional oil production under the Royalty Framework range from a base rate of 0% to a cap of 40%. This represents an increase from the previous rate cap of 35% under the tier system, but a decrease from the rate cap of 50% under the Royalty Framework prior to January 2011. New royalty rates will be determined on a monthly basis.

The new Royalty Framework also eliminated the previous tier system for natural gas, which was also based on the vintage or discovery date of the gas, and implemented a sliding rate formula based on both the commodity price of the gas and well production. This eliminated the option to use a corporate average reference price. The natural gas royalty formula also provides for a reduction based on the measured depth of the well below 2,000 metres (the "**Depth Factor Adjustment**"), as well as the acid gas content of the produced gas (the "**Acid Gas Adjustment**"). Subject to certain available incentives, effective from the January 2011 production month royalty rates for natural gas production under the Royalty Framework range from a base rate of 5% to a cap of 36%. This represents an increase from the previous rate cap of 35% under the tier system, but a decrease from the rate cap of 50% under the Royalty Framework prior to January 2011.

Under the new Royalty Framework, the royalty rate applicable to natural gas liquids is a flat rate of 40% for pentanes and 30% for butanes and propane.

On March 11, 2010 the Government of Alberta announced modifications to the Royalty Regime (the "**Modified Royalty Framework**"), effective on January 1, 2011. The Modified Royalty Framework reduces the maximum royalty rates under the Royalty Framework as follows: for conventional oil production from 50% to 40% and for natural gas from 50% to 36%. The Modified Royalty Framework also made permanent the 5% maximum royalty rate on the first 12 production months, 50,000 barrels of oil production or 500 million cubic feet (MMcf) of gas production from a well, whichever is reached first.

In terms of oil and natural gas production obtained from lands other than Crown lands, taxes are payable to the Province of Alberta. Approximately 19% of the mineral rights in the Province of Alberta are freehold mineral rights not owned by the Crown. The tax levied in respect of freehold oil and gas production in the Province of Alberta is calculated annually based on a rate dependent on the prescribed tax rate, the quantity of produced oil or gas, and the unit value of the produced oil or gas.

Alberta Incentives

Pursuant to the new Royalty Framework, the Deep Oil Exploratory Well Program, the Enhanced Recovery of Oil Royalty Reduction Program ("**EOR Program**"), the Natural Gas Deep Drilling Program, and the Innovative Energy Technologies Program (the "**IETP**") were either created or retained.

The *Deep Oil Exploratory Well Regulation* provides a limited royalty exemption for qualifying exploratory oil wells spudded or deepened between January 1, 2009 and December 31, 2013 that are deeper than 2,000 metres and have a producing interval below 2,000 metres. Existing oil wells approved under the discontinued Third Tier Exploratory Well Royalty Exemption and qualifying for the Deep Oil Exploratory Well Program were transitioned into the new program on January 1, 2009.

With respect to the EOR Program, the *Enhanced Recovery of Oil Royalty Reduction Regulation* provides that Alberta Energy may approve royalty reductions for qualifying enhanced oil recovery projects.

The *Natural Gas Deep Drilling Regulation* provides a limited royalty reduction for qualifying exploratory and development natural gas wells spudded or deepened on or after May 1, 2010, with producing intervals that are deeper than 2,000 metres.

The IETP was originally intended to promote producers' investment in research, technology and innovation for the purposes of improving environmental performance while creating commercial value. This program has been retained under the new Royalty Framework. The IETP provides royalty reductions which are presumed to reduce financial risk. Alberta Energy determines which projects qualify for the IETP, as well as the level of support that will be provided. The deadline for the IETP's fifth round of applications was November 15, 2009.

On March 3, 2009, the Government of Alberta announced the New Well Royalty Reduction (the "**NWRR**") incentive program. The *New Well Royalty Reduction Regulation* provides that the NWRR will be available to qualifying wells that commence or recommence producing conventional oil or natural gas between April 1, 2009 and March 31, 2011. Pursuant to the *New Well Royalty Reduction Regulation*, the NWRR reduces royalties on production from qualifying wells to a maximum royalty rate of 5% until the earlier of either 12 production months from the date of first production, the date that the first 7949 cubic metres of eligible oil or oil equivalent is produced, the date the well becomes part of a Project under the *Oil Sands Royalty Regulation, 2009*, or March 31, 2012, whichever occurs first.

On March 11, 2010, as part of a larger modification of royalty rates under the Royalty Framework, the Government of Alberta announced that the NWRR will become a permanent feature of Alberta's royalty regime. The NWRR is now referred to as the New Well Royalty Rate as it provides for a 5% royalty from the outset, as opposed to reducing an existing royalty to 5%. Effective January 1, 2011, no new wells will be allowed to select the transitional royalty rates. Wells that have already selected the transitional royalty rates will have the option to stay with those rates or switch to the new rates effective January 1, 2011.

In addition, on May 27, 2010 the Government of Alberta announced further initiatives to stimulate investment in emerging resources and technologies. The Shale Gas New Well Royalty Rate ("**SGNWRR**") reduced royalties on production from qualifying wells to a maximum royalty rate of 5% for 36 production months, with no limitation on volume. The Coalbed Methane New Well Royalty Rate ("**CMNWRR**") reduced royalties on production from qualifying wells to a maximum royalty rate of 5% until the earlier of either 36 production months from date of first production or the date that the first 11,924 cubic metres of oil equivalent is produced. The Horizontal Gas New Well Royalty Rate ("**HGNWRR**") reduced royalties on production from qualifying wells to a maximum royalty rate of 5% until the earlier of either 18 production months from date of first production or the date that the first 7949 cubic metres of oil equivalent is produced. Finally, the Horizontal Oil New Well Royalty Rate ("**HONWRR**") reduced royalties on production from qualifying wells to a maximum royalty rate of 5% until the prescribed time or volume limit is met.

The NWRR applies to wells under the Royalty Framework. In relation to conventional oil wells eligible for both the NWRR and the Deep Oil Exploratory Well Program, the date constraints and volume limits under each program run concurrently. In relation to natural gas wells eligible for both the NWRR and the Natural Gas Deep Drilling Program ("**NGDDP**") and any of the 5% royalty rates, including the NWRR, the HGNWRR, the CMNWRR or the SGNWRR, the 5% royalty rate will be applied first, with the NGDDP benefits applied after the expiration of the 5% rate. However, the 60 calendar month benefit under the NGDDP begins on the well's finished drilling date, not with the expiry of the 5% royalty rate. In addition, the NWRR reduces the royalty reduction that is available for wells under the EOR Program and the IETP.

The implementation of changes to royalties could have a negative impact on net earnings, funds from operations, cash flow from operating activities, operating netbacks, and reserve values, which could create uncertainty as to the recoverability of the carrying value of the Corporation's petroleum and natural gas assets.

Manitoba Royalties

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.

Manitoba Incentives

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 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 m3.

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 m3; (ii) deep exploratory well drilled below the Birdbear Formation earns a HOV of 8,000 m3, and (iii) deep development well completed for production in the Birdbear or deeper formation earns a HOV of 8,000 m3.

The *Horizontal Well Incentive* provides licensees of horizontal wells drilled prior to January 1, 2018 with a HOV of 8,000 m3.

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 m3, 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 m3 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 will be phased out January 1, 2015. Until then companies will be able to assign a one-time maximum of 2,000 m3 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 are no longer able to assign HOV from a well to their HOV account or transfer holiday oil 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.

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.

Environmental Protection Requirements

All phases of the oil and gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of international conventions and federal, provincial and municipal 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, requirements with respect to oilfield waste handling and storage, habitat protection, and minimum setbacks of oil and gas activities from fresh water bodies. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities.

Environmental laws may impose remediation obligations and costs on "persons responsible" with respect to contaminated property, including persons responsible for the substance causing the contamination, persons responsible for the release, past and present owners of the property, and occupiers of the property. Compliance with such legislation can require significant expenditures and a breach may result in the imposition of fines and penalties, some of which may be material, and in the suspension or revocation of necessary licences and approvals, as well as civil liability for damage caused by pollution. Certain environmental protection legislation may subject the Corporation 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.

It is expected that any regulations eventually implemented by the Government of Canada will have an impact on the oil and gas industry as a whole, which could result in increased costs for the Corporation to comply with such legislation. In the meantime, the Corporation will continue to monitor the policies of the Government of Canada and any resulting legislation with respect to GHG emissions. The U.S. Environmental Protection Agency ("**EPA**") is proceeding to regulate greenhouse gases 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.

Environmental legislation in the Province of Alberta is, for the most part, set out in the *Environmental Protection and Enhancement Act* (the "**EPEA**") and the *Oil and Gas Conservation Act* ("**Alberta OGCA**"). The EPEA and the Alberta OGCA impose strict environmental standards with respect to releases of effluents and emissions, include reporting and monitoring obligations, and impose significant penalties for non-compliance. For example, regulations enacted under the EPEA target sulphur oxide and nitrous oxide emissions from oil and gas operations. On June 17, 2013, Alberta introduced the *Responsible Energy Development Act*, under which the Alberta Energy Regulatory ("**AER**") superseded the Energy Resources Conservation Board ("**ERCB**") as the provincial energy regulatory. The AER is responsible for the administration of both the *Environmental Protection and Enhancement Act* and the *Oil and Gas Conservation Act*.

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 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, 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. The Government of Alberta is presently developing the South Saskatchewan regional plan. The impact of the implantation of the final South Saskatchewan regional plan on the Corporation is uncertain.

Upon completion of the Arrangement, the Corporation commenced 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 "**Saskatchewan OGCA**"). The EMPA and the Saskatchewan OGCA 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.

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

Upon completion of the Arrangement, the Corporation owns oil and natural gas properties and related assets in Manitoba, and as such is subject to the *Oil and Gas Act* which incorporates provisions related to the environment from *The Environment 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.

Spartan, through its wholly-owned subsidiaries, owns oil and natural gas properties and related assets in North Dakota in the United States. In North Dakota, the North Dakota Department of Health regulates practices in oil and gas exploration and production and enforces applicable laws to ensure protection of human health, safety and environmental health. The Environmental Health Division governs public health, air quality, waste management and water quality (surface and groundwater). The North Dakota Department of Health, Water Diversions regulates water injection.

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 estimates well abandonment 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.

Spartan does not forecast or anticipate incurring any significant costs in the near term related to abandonment and reclamation costs. Estimated costs of abandonment were included in the Spartan Reserve Report (as defined herein) and the Renegade Reserves Report (as defined herein) as a deduction in determining future net revenue. The total estimated abandonment costs in respect of proved reserves using forecast prices is $28.78 million undiscounted ($8.17 million using a 10% discount rate). All of such amounts were deducted as abandonment costs in estimating future net revenue of Spartan in respect of proved reserves. Please see "*Pro Forma Reserves Data After Giving Effect to the Arrangement*" for additional information. No allowance for salvage value was included in these costs. The total proved plus probable abandonment and reclamation costs are $32.18 million (undiscounted) and $6.10 million (discounted at 10%). As at December 31, 2013, the Corporation has accrued $28.0 million for the fair value of the decommissioning liability. The decommissioning liability is anticipated to be funded by future cash flow as required. No abandonment expenses were incurred in 2013.

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, as well as 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;
- operations 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. This 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, Canada and in North Dakota, United States. 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.

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.

Failure to Realize Anticipated Benefits of the Arrangement

Spartan has completed the Arrangement to strengthen its position in the oil and gas industry and to create the opportunity to realize certain benefits including, among other things, increased production and revenue. Achieving the benefits of the Arrangement and any future acquisitions the Corporation may complete will depend in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner, as well as the Corporation's ability to realize the anticipated growth opportunities and synergies from assets obtained through the Arrangement or future acquisitions with those of the Corporation. This integration requires the dedication of substantial management effort, time and resources which may divert management's focus and resources from other strategic opportunities and from operational matters during this process. The integration process may result in the loss of key employees and the disruption of ongoing business, customer and employee relationships that may adversely affect the Corporation's ability to achieve the anticipated benefits of the Arrangement and any future acquisitions.

Evaluation of Renegade's Assets

Acquisitions of oil and natural gas properties or companies are based in large part on engineering, environmental and economic assessments made by the acquiror, independent engineers and consultants. These assessments include a series of assumptions regarding such factors as recoverability and marketability of oil and natural gas, environmental restrictions and prohibitions regarding releases and emissions of various substances, future prices of oil and gas and operating costs, future capital expenditures and royalties and other government levies which will be imposed over the producing life of the reserves. Many of these factors are subject to change and are beyond the control of the Corporation. All such assessments involve a measure of geologic, engineering, environmental and regulatory uncertainty that could result in lower production and reserves or higher operating or capital expenditures than anticipated.

Although title and environmental reviews are conducted prior to any purchase of resource assets, such reviews cannot guarantee that any unforeseen defects in the chain of title will not arise to defeat the Corporation's title to certain assets or that environmental defects or deficiencies do not exist.

Potential Undisclosed Liabilities Associated with the Arrangement

There may be liabilities that the Corporation failed to discover or was unable to quantify in its due diligence, which it conducted prior to the completion of the Arrangement and the Corporation may not be indemnified for some or any of these liabilities.

Operational and Reserves Risks Relating to Renegade's Assets

The risk factors set forth in this AIF relating to the oil and natural gas business, environmental matters and the operations and reserves of the Corporation apply equally in respect of the reserves acquired by the Corporation through the acquisition of Renegade and the Renegade Reserve Report. In particular, the reserve and recovery information contained in the Renegade Reserves Report are only estimates and the actual production from and ultimate reserves of the properties evaluated therein may be greater or less than the estimates contained in such reports.

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 present global credit crisis 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 lower 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 stock options under the Corporation's stock option plan.

Global Financial Crisis

Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the deterioration of global economic conditions, have caused significant volatility to commodity prices. These conditions worsened in 2008 and continued to a certain extent from that time through 2012, causing a loss of confidence in the broader U.S. and global credit and financial markets and resulting in the collapse of, and government intervention in, major banks, financial institutions and insurers and creating a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various actions by governments and the ongoing recovery in the global economic situation, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to deteriorate and stock markets to decline, at times substantially. These factors have negatively impacted company valuations and may continue to impact the performance of the global economy going forward. Although economic conditions improved towards the latter portion of 2009, and during portions of 2012 and 2013, the recovery from the recession has been slow in various jurisdictions including in Europe and the United States and has been impacted by various ongoing factors including sovereign debt levels and high levels of unemployment which continue to impact commodity prices and consumer confidence which has resulted in high volatility in the stock market.

Capital Lending Markets

As a result of general economic uncertainties and, in particular, the lack of risk capital available to the junior resource sector, the Corporation, along with other junior resource 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 do so 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 or 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.

Prices, Markets and Marketing

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 numerous factors beyond its control. Spartan's ability to market its oil and natural gas may depend upon its ability to acquire space on pipelines that deliver 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.

The prices of oil and natural gas may be volatile and subject to fluctuation. Any material decline in prices could result in a reduction of the Corporation's net production revenue. The economics of producing from some wells may change 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. Prices for oil and gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors beyond the control of the Corporation. These factors include economic conditions, in the United States and Canada, the actions of the Organization of Petroleum Exporting Countries ("**OPEC**"), governmental regulation, political stability in the Middle East and elsewhere, the foreign supply of oil and gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. 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. 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 and prospects.

Petroleum 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, OPEC actions and the ongoing credit and liquidity concerns. 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.

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. Spartan'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 the Corporation's control, including:

- the availability of processing capacity;
- 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 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, the Corporation 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.

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. 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.

The royalty regime in Alberta, Saskatchewan 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.

Climate Change

Canada is a signatory to the United Nations Framework Convention on Climate Change 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 Protection Requirements*" above.

Variations in Foreign Exchange Rates and Interest Rates

World oil and gas prices are quoted in United States 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/United States 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 United States dollars in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the United States dollar; however, if the Canadian dollar declines in value compared to the United States dollar, 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, and 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

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. 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. 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 in effect for the Corporation. 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.

United States

Spartan, through its wholly-owned subsidiaries, owns oil and natural gas properties and related assets in North Dakota in the United States. Spartan's oil and natural gas operations in the United States are regulated by administrative agencies under statutory provisions of the states where such operations are conducted and by certain agencies of the federal government for operations on federal leases. These statutory provisions regulate matters such as the exploration for and production of crude oil and natural gas, including provisions related to permits for the drilling of wells, bonding requirements in order to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, and the abandonment of wells. Spartan's operations in the United States are also subject to various conservation laws and regulations which regulate matters such as the size of drilling and spacing units or proration units, the number of wells which may be drilled in an area, and the unitization or pooling of crude oil and natural gas properties. In addition, state conservation laws sometimes establish maximum rates of production from crude oil and natural gas wells, generally prohibit the venting or flaring of natural gas, and impose certain requirements regarding the ratability or fair apportionment of production from fields and individual wells.

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 energy generation devices could reduce the demand for crude oil and other liquid hydrocarbons. 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.

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.

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.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Disclosure of Reserves Data and Other Information as of Financial Year Ended December 31, 2013

The reserves data herein is based upon a report prepared by Sproule, dated February 6, 2014, with an effective date of December 31, 2013 (the "**Spartan Reserve Report**") evaluating the crude oil, natural gas liquids and natural gas reserves of Spartan as at December 31, 2013. The reserves data set forth below is based upon an evaluation of the Spartan Reserve Report. The Reserves 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 we believe is important to the readers of this information. The following tables provide summary information presented in the Spartan Reserve Report effective December 31, 2013 and based on the Sproule December 31, 2013 price forecast.

As at December 31, 2013 all of Spartan's Canadian reserves were located in the Province of Alberta. 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 natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, 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, 2013
FORECAST PRICES AND COSTS

	Light & Medium Oil		**Heavy Oil**		**Natural Gas (non-associated & associated)**		**Natural Gas Liquids**		**Barrels of Oil Equivalent**	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mmcf)	(mmcf)	(mbbl)	(mbbl)	(MBOE)	(MBOE)
Proved										
Developed Producing	446.0	350.4	-	-	1,362	1,217	6.8	4.7	679.8	557.9
Developed Non-Producing	87.8	72.9	-	-	330	293	1.7	1.4	144.4	123.1
Undeveloped	214.2	178.4	-	-	341	299	1.7	1.5	272.7	229.7
Total Proved	**747.9**	601.7	**-**	**-**	**2,032**	**1,810**	**10.2**	7.6	**1,096.9**	910.9
Probable	308.2	242.8	-	-	856.8	758	4.3	3.4	455.3	372.5
Total Proved plus	**1,056.1**	844.5	**-**	**-**	**2,889.6**	**2,568**	**14.5**	10.9	**1,552.2**	1,283.4

Probable

Notes:
(1) Columns may not add due to rounding.
(2) Natural gas volumes include solution gas volumes associated with Spartan's light and medium crude oil reserves.
(3) 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					Unit Value
Entity Description	**0% M$**	**5% M$**	**10% M$**	**15% M$**	**20% M$**	**0% M$**	**5% M$**	**10% M$**	**15% M$**	**20% M$**	
Proved											
Producing	20,660	18,196	16,294	14,791	13,578	20,660	18,196	16,294	14,791	13,578	29.20
Developed Nonproducing	5,470	3,445	2,252	1,521	1,058	5,470	3,445	2,252	1,521	1,058	18.29
Undeveloped	7,955	6,905	6,055	5,357	4,775	6,886	6,080	5,402	4,830	4,342	26.35
Total Proved	**34,085**	**28,546**	**24,601**	**21,668**	**19,411**	**33,016**	**27,720**	**23,948**	**21,141**	**18,978**	**27.01**
Total Probable	16,058	11,625	8,799	6,905	5,579	12,141	8,760	6,614	5,180	4,179	23.62
Total Proved plus Probable	**50,143**	**40,171**	**33,400**	**28,573**	**24,990**	**45,157**	**36,480**	**30,562**	**26,321**	**23,157**	**26.02**

Notes:
(1) Utilizes Sproule's price forecast as of December 31, 2013 as detailed below.
(2) Values are net of abandonment liabilities.
(3) Columns may not add due to rounding.

TOTAL FUTURE NET REVENUE (UNDISCOUNTED) AS OF DECEMBER 31, 2013 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	73,214	13,149	21,653	3,581	745	34,085	1,069	33,016
Proved Plus Probable	106,316	19,526	31,530	4,295	822	50,143	4,986	45,157

FUTURE NET REVENUE BY PRODUCTION GROUP AS OF DECEMBER 31, 2013 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)	21,236	28.72
	Natural Gas (including associated by-products)	3,365	19.61
Proved Plus	Light and Medium Crude Oil (including solution gas and	29,191	27.61

Probable	other by-products)		
	Natural Gas (including associated by-products)	4,209	18.59

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 oil and 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.

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, 2013, as follows:

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
FORECAST PRICES AND COSTS

Year	WTI Cushing Oklahoma ($US/bbl)[1]	Edmonton Par Price 40° API ($Cdn/bbl)[2]	Cromer LSB 35° API ($Cdn/bbl)[3]	Natural Gas AECO ($Cdn/MMBTu)	Pentanes Plus FOB Field Gate ($Cdn/bbl)	Butanes FOB Field Gate ($Cdn/bbl)	Inflation Rate %/year	Exchange Rate ($US/$CDN)
Forecast								
2014	94.65	92.64	90.64	4.00	103.50	69.05	1.5	0.94
2015	88.37	89.31	87.31	3.99	99.78	66.57	1.5	0.94
2016	84.25	89.63	87.63	4.00	100.14	66.81	1.5	0.94
2017	95.52	101.62	99.62	4.93	113.53	75.74	1.5	0.94
2018	96.96	103.14	101.14	5.01	115.24	76.88	1.5	0.94
2019	98.41	104.69	102.69	5.09	116.97	78.03	1.5	0.94
2020	99.89	106.26	104.26	5.18	118.72	79.20	1.5	0.94
2021	101.38	107.86	105.86	5.26	120.50	80.39	1.5	0.94
2022	102.91	109.47	107.47	5.35	122.31	81.60	1.5	0.94
2023	104.45	111.12	109.12	5.43	124.14	82.82	1.5	0.94
2024	106.02	112.78	110.78	5.52	126.01	84.06	1.5	0.94
Thereafter				Escalation Rate of 1.5%				

Notes:
(1) West Texas Intermediate at Cushing Oklahoma 40 degrees API, 0.4% sulphur.
(2) Edmonton Light Sweet 40 degrees API, 0.3% sulphur.
(3) Cromer LSB (35◦ degrees API Light stream).

Weighted average historical price realized, including the Spartan Acquired Assets and the Renegade Assets, for the year ended December 31, 2013, after hedging, was $82.37/Bbl for crude oil, $52.76/Bbl for NGLs and $3.10/Mcf for natural gas.

Estimated future abandonment costs related to a working interest have been taken into account by Sproule in determining reserves that should be attributed to a property and in determining the aggregate future net revenue therefrom, there was deducted the reasonable estimated future well abandonment costs. No allowance was made, however, for reclamation of well sites or the abandonment of any 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 Oil			Heavy 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)**	**Gross Proved (Mbbl)**	**Gross Probable (Mbbl)**	**Gross Proved + Probable (Mbbl)**
December 31, 2012	669.3	439.7	1109.0	-	-	-	0	0	0
Discoveries	-	-	-	-	-	-	0	0	0
Extensions	129.6	43.2	172.8	-	-	-	0.8	0.3	1.1
Infill Drilling	-	-	-	-	-	-	-	-	-
Technical Revisions	102.6	(182.6)	(80.0)	-	-	-	13.6	4.0	17.6
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-
Economic Factors	9.6	7.9	17.5	-	-	-	-	-	-
Production	(163.2)	0	(163.2)	-	-	-	(4.2)	0	(4.2)
December 31, 2013	747.9	308.2	1,056.1	-	-	-	10.2	4.3	14.5

Factors	Associated and Non-Associated Gas Gross Proved (Mmcf)	Gross Probable (Mmcf)	Gross Proved + Probable (Mmcf)	Natural Gas Solution Gross Proved (Mmcf)	Gross Probable (Mmcf)	Gross Proved + Probable (Mmcf)
December 31, 2012	2,001	633	2,634	708	945	1,653
Discoveries	0	0	0	0	0	0
Extensions	0	0	0	163	54	217
Infill Drilling	-	-	-	-	-	-
Technical Revisions	(467)	(333)	(800)	343	(475)	(132)
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	17	9	26	-	-	-
Production	(587)	0	(587)	(160)	0	(160)
December 31, 2013	964	309	1,273	1,069	548	1,617

Reserves Data

Undeveloped Reserves

The following tables set forth the gross proved undeveloped reserves and the gross probable undeveloped reserves, each by product type, attributed to Spartan's assets for the year ended December 31, 2013 and, in the aggregate, before that time based on forecast prices and costs.

Proved Undeveloped Reserves

	Light and Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Natural Gas (MMcf)		Natural Gas Liquids (Mbbl)	
	First Attributed Gross	Booked Gross	First Attributed Gross	Booked Gross	First Attributed Gross	Booked Gross	First Attributed Gross	Booked Gross
Prior to December 31, 2013	64.2	133.6	-	-	46.0	191.0	-	-
December 31, 2013	129.6	214.2	-	-	163.0	341.0	0.8	1.7

Probable Undeveloped Reserves

	Light and Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Natural Gas (MMcf)		Natural Gas Liquids (Mbbl)	
	First Attributed Gross	Booked Gross	First Attributed Gross	Booked Gross	First Attributed Gross	Booked Gross	First Attributed Gross	Booked Gross
Prior to December 31, 2013	39.4	113.4	-	-	28.0	224.0	-	-
December 31, 2013	43.2	92.0	-	-	54.0	157.0	0.3	0.8

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 three years. 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 (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, prior to giving effect to the Arrangement and the Asset Acquisition, attributable to the reserve categories noted below:

Year	Forecast Prices and Costs (M$)	
	Proved Reserves	Proved Plus Probable Reserves
2014	$2,278	$2,992
2015	$817	$817
2016	$46	$46
2017	$0	$0
2018	$0	$0
Thereafter	$442	$442
Total Undiscounted	$3,581	$4,295
Total Discounted at 10%	$3,172	$3,855

The future development costs are capital expenditures required in the future for Spartan to convert proved undeveloped reserves and probable reserves to proved developed producing reserves. The undiscounted development costs are $3.58 million for proved reserves and $4.30 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.

Pro Forma Reserves Data After Giving Effect to the Arrangement

The summary below sets forth Spartan's gross reserves as at December 31, 2013, after giving effect to the acquisition of Renegade as though such acquisition had occurred on December 31, 2013, but excluding reserves associated with assets disposed of by Renegade to Surge Energy Inc. in the first quarter of 2014 (the "**Surge Assets**"). The reserves set forth below represent an aggregate of: (a) the reserves of Spartan as at December 31, 2013, as evaluated in the Spartan Reserves Report; (b) reserves associated with the Spartan Acquired Assets, as evaluated in an independent report prepared by Sproule on March 31, 2014 (the "**Renegade Reserve Report**"); and (c) the reserves of Renegade as at December 31, 2013, as evaluated in the Renegade Reserve Report, exclusive of the reserves associated with the Surge Assets and the Spartan Acquired Assets (the "**Renegade Assets**"). The figures in the following tables have been prepared in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101.

Summary of Gross Oil and Gas Reserves as of December 31, 2013

	Oil Gross	**Natural Gas (Associated & Non-Associated)** Gross	**Natural Gas Liquids** Gross	**Barrels of Oil Equivalent** Gross
	(Mbbl)	(MMcf)	(Mbbl)	(Mboe)
Proved				
Developed Producing	10,909.1	6,172.6	424.3	12,362.2
Developed Non-Producing	167.9	343.2	3.6	228.7
Undeveloped	5,444.6	2,546.4	156.6	6,025.6
Total Proved	**16,521.6**	**9,062.2**	**584.5**	**18,616.5**
Probable	6,746.9	3,584.5	226.0	7,570.4

	Oil	Natural Gas (Associated & Non-Associated)	Natural Gas Liquids	Barrels of Oil Equivalent
	Gross	Gross	Gross	Gross
	(Mbbl)	(MMcf)	(Mbbl)	(Mboe)
Total Proved plus Probable	**23,268.5**	**12,647.1**	**810.5**	**26,186.9**

Summary of Net Present Values and Future Revenue as of December 31, 2013

	Net Present Value before Income Taxes Discounted at (% per Year) (M$)				
	0%	5%	10%	15%	20%
Proved					
Developed Producing	524,947	418,046	350,079	303,202	268,933
Developed Non-Producing	7,251	4,961	3,563	2,670	2,076
Undeveloped	209,422	142,164	99,912	71,753	52,098
Total Proved	**741,620**	**565,171**	**453,554**	**377,625**	**323,107**
Probable	397,422	246,749	171,246	127,595	99,830
Total Proved plus Probable	**1,139,042**	**811,920**	**624,800**	**505,220**	**422,937**

Future Development Costs

The following table sets forth development costs deducted in the estimation of Spartan's future net revenue, after to giving effect to the Arrangement and the Asset Acquisition, attributable to the reserve categories noted below:

	Forecast Prices and Costs (M$)	
Year	**Proved Reserves**	**Proved Plus Probable Reserves**
2014	$46,327	$47,219
2015	$37,178	$41,711
2016	$38,118	$39,682
2017	$26,058	$36,172
2018	$388	$776
Thereafter	$442	$442
Total Undiscounted	$148,509	$166,000
Total Discounted at 10%	$126,226	$139,788

The future development costs are capital expenditures required in the future for Spartan to convert proved undeveloped reserves and probable reserves to proved developed producing reserves. The undiscounted development costs are $148.51 million for proved reserves and $166.0 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

Alberta

Alexander

The Alexander property is located northwest of Edmonton in Townships 55-56, Ranges 26-27, W4M. Spartan has an average 90% working interest in 18,990 acres of mineral rights. Since 2011, the Corporation has drilled, cased completed and tied-in six successful oil wells in the Detrital zone on the lands. The Corporation drilled an additional three (2.7 net) oil wells in the Detrital zone in the first quarter of 2014. 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.

Senex - Slave Point

The Slave Point property includes 35,360 gross (35,360 net) acres of land in Senex targeting the Slave Point formation. Spartan believes that it has identified undeveloped Slave Point pools within its land base which have the potential to be developed with horizontal multi-stage fracture technology. This asset includes a licensed inventory of horizontal wells and a vertical well.

Southeast Saskatchewan

The Southeast Saskatchewan properties are located in the conventional Mississippian subcrop trends. This includes a significant acreage position at Workman, Crystal Hills, Redverse, Mair, Wordsworth, Queensdale, Cantal and Elcott/Souris Flat targeting the Souris Valley, Frobisher, Kisbey, Alida and Midale formations. Seventeen gross (11.3 net) wells were drilled on these properties in 2013 and an additional 6 gross (5.3 net) wells were drilled in the first quarter of 2014. Spartan intends to drill an additional 44 gross (40 net) wells in southeast Saskatchewan in 2014.

Workman

The Workman property includes approximately 19,746 gross (16,283 net) acres of land targeting the Frobisher formation. This area consists principally of an 86% working interest on operated production from the Workman Frobisher Voluntary Units 1 and 3. The production from this area is predominantly processed at the 76.35% working interest multi-well battery.

Crystal Hills - Parkman

The Parkman property includes approximately 29,626 gross (26,931 net) acres of land targeting the Souris Valley formation. In 2013, Renegade drilled two gross (1.0 net) wells with a 100% success rate. Spartan has non-proprietary 3D seismic coverage over the pool including a 35 square kilometre 3D seismic over this Parkman acreage.

Redvers-Mair

The Redvers property includes approximately 16,531 gross (16,079 net) acres of land targeting the Souris Valley formation. During 2013, while owned by Renegade, no wells were drilled as Renegade used the year to evaluate the long term economic viability of the area. Due to the high water cut in the area, the long term well performance is critical to determine the upside potential. Spartan owns 87.5 square kilometres of 3D seismic over the producing fields. Spartan intends to further evaluate this asset.

Wordsworth

The Wordsworth property includes approximately 11,580 gross (10,795 net) acres of land targeting the Frobisher formation. During 2013, Renegade drilled 3 gross (2.5 net) wells targeting the Frobisher and Kisbey formations. One of these vertical wells proved an extension to the existing offset pool which is supported via seismic interpretation. In 2013, Renegade shot two 3D seismic programs in the area, totalling 68.9 square kilometres and owns a total of 178.2 square kilometres of seismic data in the area.

Queensdale

The Queensdale property includes approximately 26,640 gross (23,729 net) acres of land targeting the Frobisher formation. In 2013, Renegade drilled six gross (4.6 net) wells with an average 30 day initial rate of 199 bbl/d. An additional four gross (3.3 net) wells were drilled on the property in the first quarter of 2014 with an average 30 day initial production rate of 189 bbl/d.

Cantal

In 2013, Renegade shot a 20.5 square kilometre 3D seismic program over a portion of the Cantal acreage. Spartan is planning a drilling program supported by the technical evaluation of the pool and targeting the lower most producing interval of the Frobisher formation.

Elcott/Souris Flat

The Corporation has approximately 19,700 gross (16,300 net) acres of land in the Elcott/Souris Flat area of southeast Saskatchewan targeting the Midale formation. The Corporation plans to drill up to 9 fracture stimulated horizontal wells in this area in 2014.

West Central Saskatchewan - Dodsland

The Dodsland property includes approximately 11,161 gross (9,734 net) acres of land targeting the Viking formation. In 2013, Renegade drilled 36 gross (35.5 net) horizontal wells with 100% success rate, and 10 (9.5 net) wells were drilled in the first quarter of 2014. The Corporation plans to drill an additional 11 (10.5) horizontal wells in west central Saskatchewan in the remainder of 2014.

Waskada, Manitoba

The Waskada property includes approximately 4,040 gross (3,056 net) acres of land targeting the Spearfish/Amaranth formation of southwest Manitoba.

North Dakota

The North Dakota property includes 26,577 gross (15,990 net) acres of land in Renville County, North Dakota. In late 2010, Renegade drilled a horizontal well targeting the Bakken formation. The horizontal well encountered hydrocarbons in the Bakken formation proving a new pool, however, there has not been further development of this acreage since 2010. Spartan intends to evaluate the potential of this acreage in 2014.

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, 2013, both before and after giving effect to the Arrangement and the Asset Acquisition.

	Producing				Non-Producing [3]			
	Oil		Gas		Oil		Gas	
	Gross[1]	Net[2]	Gross[1]	Net[2]	Gross[1]	Net[2]	Gross[1]	Net[2]
As at December 31, 2013	14	12.3	13	9.7	0.9	6.1	15	11.1
After giving effect to the Arrangement and the Asset Acquisition	1,153	768.5	16	10.7	141	98.2	16	12.1

Notes:
(1) "Gross" means total number of wells in which we hold 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.

Properties with No Attributable Reserves

The following table summarizes Spartan's undeveloped land holdings (in acres) as at December 31, 2013.

	Unproved Properties		
	Gross[1]	Net[2]	Net Acres Expiring Within One Year
As at December 31, 2013	23,108	22,878	12,923.2
After giving effect to the Arrangement and the Asset Acquisition			
Canada	126,953.8	118,791	21,742.3
United States	21,500.2	13,218	8,886.9

Notes:
(1) "Gross" means the total number of acres in which we hold 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.

Prior to the Arrangement, Renegade managed its commodity price risk by financially hedging a portion of its crude oil sales through the use of financial derivative contracts. The financial derivative contracts that were in place with Renegade were acquired by Spartan pursuant to the Arrangement. As at April 30, 2014, Spartan had the following crude oil commodity contracts in place:

Period	Commodity	Contract	Quantity Contracted	Contract Price[1]
January 2014 — December 2014	Crude Oil	Swap	500bbls/d	CAD $91.00/bbl
January 2014 — December 2014	Crude Oil	Swap	500bbls/d	CAD $91.00/bbl
January 2014 — December 2014	Crude Oil	Swap	500bbls/d	CAD $91.05/bbl
January 2014 — December 2014	Crude Oil	Swap	500bbls/d	CAD $91.20/bbl
January 2014 — December 2014	Crude Oil	Swap	1,000bbls/d	CAD $91.70/bbl
January 2014 — December 2014	Crude Oil	Swap	1,000bbls/d	CAD $96.00/bbl
January 2014 – December 2014	Natural Gas	Swap	700GJ/d	CAD $3.58/GJ

Note:
(1) NYMEX WTI monthly average converted to Canadian dollars.

Additional Information Concerning Abandonment Costs

Spartan estimates well abandonment 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 costs of abandonment were included in the Spartan Reserve Report as a deduction in determining future net revenue. The total estimated abandonment costs in respect of proved reserves using forecast prices with respect to net wells is $0.745 million undiscounted ($0.411 million using a 10% discount rate). All of such amounts were deducted as abandonment 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 $0.822 million (undiscounted) and $0.383 million (discounted at 10%). The table below indicates the expected timing of well abandonment costs for Spartan.

The following tables set forth abandonment costs deducted in the estimation of Spartan's future net revenue:

Forecast Prices and Costs (Total Proved) ($000)

Year	Abandonment Costs (Undiscounted)
2014	22
2015	81
2016	58
Thereafter	584
Total Undiscounted	745
Total Discounted at 10%	411

Forecast Prices and Costs (Total Proved & Probable) ($000)

Year	Abandonment Costs (Undiscounted)
2014	22
2015	53
2016	58
Thereafter	689
Total Undiscounted	822
Total Discounted at 10%	383

The expected total reserve well abandonment costs, net of reclamation and estimated salvage value, included in the Renegade Reserve Report under the proved reserves category is $28.032 million undiscounted ($7.76 million discounted at 10%), of which a total of $0.631 million is estimated to be incurred in 2014, 2015 and 2016.

Tax Horizon

Depending on levels of production, commodity prices, acquisitions and capital expenditures, Spartan will not pay current income taxes until at least year 2017.

Costs Incurred

The following tables summarize by Spartan's property acquisition costs, exploration costs and development costs for the year ended December 31, 2013:

	($000)
Property Acquisition Costs	
Proved Properties	-
Unproved Properties	19
Exploration Costs	-
Development Costs	3,497
Total:	3,516

Capital Expenditures

The following table summarizes capital expenditures related to Spartan's activities for the year ended December 31, 2013:

	($000)
Land/Seismic	124
Drilling and Completion	1,920
Equipment and Facilities	1,373
Capitalized G&A Expenses/Other	99
Plus: Acquisitions	-
Less: Dispositions	-
Net Expenditures	3,516

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, 2013:

Canada	**Exploration**		**Development**	
	Gross	**Net**	**Gross**	**Net**
Light and Medium Oil	-	-	2	1.7
Natural Gas	-	-	-	-
Service	-	-	-	-
Dry	-	-	-	-
Total:	-	-	-	-

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, 2014, 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*".

Total Proved

	Light and Medium Oil (Including C5+) *(Bbls/d)*	Heavy Oil *(Bbls/d)*	Natural Gas *(Mcf/d)*	Natural Gas Liquids *(Bbls/d)*	BOE *(BOE/D)*
Total (Alberta)	476	-	1,257	-	686

Total Proved Plus Probable

	Light and Medium Oil (Including C5+) *(Bbls/d)*	Heavy Oil *(Bbls/d)*	Natural Gas *(Mcf/d)*	Natural Gas Liquids *(Bbls/d)*	BOE *(BOE/D)*
Total (Alberta)	509	-	1,378	-	739

The following table sets forth the volume of Spartan's gross working interest production estimated for the year ending December 31, 2014 after giving effect to the Arrangement, 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*".

Total Proved

	Light and Medium Oil (Including C5+) *(Bbls/d)*	Heavy Oil *(Bbls/d)*	Natural Gas *(Mcf/d)*	Natural Gas Liquids *(Bbls/d)*	BOE *(BOE/D)*
Proved					
Alberta	476	-	1,257	-	686
Saskatchewan	5,418	-	1,836	123	5,847
Total	5,894	-	3,093	123	6,533

Total Proved Plus Probable

	Light and Medium Oil (Including C5+) *(Bbls/d)*	Heavy Oil *(Bbls/d)*	Natural Gas *(Mcf/d)*	Natural Gas Liquids *(Bbls/d)*	BOE *(BOE/D)*
Proved plus Probable					
Alberta	509	-	1,378	-	739
Saskatchewan	5,750	-	1,946	129	6,204
Total	6,259	-	3,324	129	6,943

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:

	2013 Quarter Ended			
	Q4 **Dec. 31**	**Q3** **Sept. 30**	**Q2[(1)]** **June 30**	**Q1** **March 31**
Average Daily Production[(1)]				
Oil (Bbls/d)	410	477	450	441
Liquids (Bbls/d)	15	15	13	14
Gas (Mcf/d)	1,434	1,857	2,240	2,685
Combined (BOE/D)	664	805	835	900
Average Price Received				
Oil ($/Bbl)	68.85	90.84	79.55	70.35
Liquids ($/Bbl)	73.59	94.46	83.18	73.49
Gas ($/mcf)	3.91	2.72	3.90	3.22
Combined ($/BOE)	52.64	62.27	54.66	45.05
Royalties Paid				
Oil ($/Bbl)	13.12	17.26	11.15	11.49
Liquids ($/Bbl)	11.50	11.48	11.32	2.65
Gas ($/mcf)	1.14	1.33	1.78	1.50
Combined ($/BOE)	8.90	11.40	9.44	6.40
Operating & Transportation Expenses				
Oil ($/Bbl)	12.66	15.28	21.24	17.94
Liquids ($/Bbl)	6.33	6.33	6.33	6.33
Gas ($/mcf)	1.25	1.25	1.25	1.25
Combined ($/BOE)	10.71	12.16	14.90	12.61
Netback Received[(2)]				
Oil ($/Bbl)	42.99	58.31	44.77	40.92
Liquids ($/Bbl)	55.76	76.64	65.52	64.52
Gas ($/mcf)	1.54	0.16	1.39	0.48
Combined ($/BOE)	33.03	38.41	30.32	26.04

Notes:
(1) Before deduction of royalties.
(2) Netback is calculated by deducting royalties paid and production costs, including transportation costs, from prices received, excluding the effects of hedging.

The following tables disclose, on a quarterly basis for the year ended December 31, 2013, certain information in respect of production, product prices received, royalties paid, operating expenses and resulting netback with respect to Spartan, after giving effect to the Arrangement:

Average Daily Production Volume

	Three Months Ended			
	Mar. 31, 2013	Jun. 30, 2013	Sep. 30, 2013	Dec. 31, 2013
Natural gas (Mcf/d)	3,995	3,302	2,822	2,314
Light and Medium Crude Oil (Bbls/d)	6,513	6,122	6,531	6,178
NGL (Bbls/d)	145	149	122	114

Total (BOE/d)	7,322	6,820	7,127	6,677

Prices Received, Royalties Paid, Production Costs and Netback – Crude Oil

($ per Bbl)	**Three Months Ended**			
	Mar. 31, 2013	Jun. 30, 2013	Sep. 30, 2013	Dec. 31, 2013
Prices Received	77.11	82.19	94.16	77.65
Royalties Paid	12.04	13.13	14.43	12.36
Production Costs	15.96	17.24	19.76	17.64
Netback[(1)]	49.11	51.82	59.96	47.65

Note:

(1) Netback is calculated by deducting royalties paid and production costs, including transportation costs, from prices received, excluding the effects of hedging.

The following table indicates Spartan's average daily production from its material properties for the year ended December 31, 2013:

	Liquids (Bbls/d)	**Gas (Mcf/d)**	**BOE (BOE/D)**
Total (Alberta)	459	2,046	800

Spartan's average production for the year ended December 31, 2012 was 57% liquids. For the year ended December 31, 2013, 83% 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, 2013, an aggregate of 248,564,811 Common Shares (approximately 62,141,000 Common Shares after giving effect to the consolidation) were issued and outstanding.

As at the date hereof, after giving effect to the share consolidation, there are 221,635,777 Common Shares issued and outstanding, 34,828,523 Warrants issued and outstanding, and the Corporation has granted 9,197,500 Options to acquire Common Shares. 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 TSXV under the symbol "SPE". The following table sets the price range and trading volume of these securities prior to giving effect to the consolidation, as reported by the TSXV for the period January 1, 2013 to December 31, 2013:

	Common Shares		
Month	**High**	**Low**	**Volume**
January	$0.210	$0.150	5,863,600
February	$0.240	$0.180	501,005
March	$0.245	$0.180	655,306
April	$0.275	$0.205	431,060
May	$0.240	$0.175	43,803
June	$0.240	$0.175	315,641
July	$0.230	$0.165	598,807
August	$0.230	$0.145	375,169
September	$0.240	$0.165	894,140
October	$0.210	$0.175	628,566
November	$0.300	$0.200	1,100,287
December	$0.800	$0.200	77,625,951

PRIOR SALES

The following table sets forth, for each class of securities of the Corporation that is outstanding but not listed or quoted on a marketplace, the price at which securities of the class have been issued during the financial year ended December 31, 2013 and the number of securities of the class issued at that price and the date on which the securities were issued, prior to giving effect to the consolidation.

Date of Issuance	Class of Securities	Number of Securities Issued	Issue or Exercise Price
December 10, 2013	Warrants	119,735,183	$0.20
December 24, 2013	Warrants	15,151,668	$0.20
December 18, 2013	Stock Options	9,230,000	$0.60

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 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. Prior to that, President of Titan Exploration Ltd., a public oil and gas exploration company, from June 2007 to December 2007. Vice President, Finance and Chief Financial Officer of Titan Exploration Ltd. from August 2004 to June 2007.
Michelle Wiggins *Calgary, Alberta*	Vice President, Finance and Chief Financial Officer		Vice President, Finance and Chief Financial Officer of Spartan Oil Corp. from June 2011 to January 2013. Prior to that Vice President, Finance and Chief Financial Officer of Spartan Exploration Ltd. from January 2008 to June 2011. Prior to that Chief Financial Officer of Titan Exploration Ltd. from June 2007 to December 2007. Prior to that Controller of Titan Exploration Ltd. from February 2005 to June 2007.
Fotis Kalantzis *Calgary, Alberta*	Vice President, Exploration		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. Prior to that Vice President Engineering & Operations of Titan Exploration Ltd. from April 2004 to December 2007.
Ed Wong *Calgary, Alberta*	Vice President, Engineering		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. Prior to that Business Unit Manager of Samson Canada Ltd., an exploration and production company, from April 2002 to September 2008.
Albert Stark *Calgary, Alberta*	Vice President, Operations		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. Prior to that Vice President Engineering & Operations of Titan Exploration Ltd. from April 2004 to December 2007.

Name	Positions Presently Held	Director Since	Principal Occupation for Previous Five Years
Thomas Boreen *Calgary, Alberta*	Vice President, Geology		Chief Geologist at Spartan Oil Corp. from June 2011 to January 2013. Prior to that held positions with Suncor, Apache Canada, Shell Canada and Home Oil.
Michael J. Stark[(1)(2)(4)] *Calgary, Alberta*	Chairman	December 10, 2013	Chairman of Spartan Oil Corp. from June 2011 to January 2013. Independent Businessman since 2006. Prior to that President of Stark Wealth Management Ltd., a financial services company, from 2003 to 2006. Prior to that National Vice President, TWC Financial Corp., a financial services company, from 2001 to 2003.
Reginald J. Greenslade[(1)(2)(3)(4)] *Calgary, Alberta*	Director	December 10, 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. Chairman, Enterra Energy Trust, an oil and gas income trust, from August 2001 to March 2006. President and Chief Executive Officer of Enterra Energy Trust from January 2005 to June 2005. President and Chief Executive Officer of JED Oil Inc., an exploration and production company, from November 2003 to January 2005.
Grant W. Greenslade[(3)(4)] *Shaunavon, Saskatchewan*	Director	December 10, 2013	Director of Spartan Oil Corp. from June 2011 to January 2013. Independent Businessman. President of Greenslade Consulting Ltd., a private oil and gas consulting company.
Donald Archibald[(1)(2)(3)] *Calgary, Alberta*	Director	December 10, 2013	Director of Spartan Oil Corp. from June 2011 to January 2013. President of Cypress Energy Corp., a private investment company, since March 2008. Prior to that Chairman and Chief Executive Officer of Cyries Energy Inc. from July 2004 to March 2008.
Thomas Budd *Calgary, Alberta*	Director	March 31, 2014	Independent businessman since July 2008. Director of Whitehall Energy Inc., Waldron Energy Corporation and Toscana Energy Income Corporation. Prior to that, President and Vice Chairman, Head of Investment Banking at Griffiths McBurney & Partners, GMP Capital Corp. and GMP Capital Trust from April 2006 to June 2008.
Sanjib Gill *Calgary, Alberta*	Corporate Secretary		Since January 2008, Partner at the law firm of McCarthy Tétrault LLP, 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 30,224,212 Common Shares representing approximately 14% of the issued and outstanding Common Shares.

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

Except as set forth below, no director, executive officer or person that is a promoter, or has been a promoter within the two years immediately preceding the date hereof, of Spartan 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; (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; and no director, executive officer or person that is a promoter, or has been a promoter within the two years immediately preceding the date hereof of Spartan, or to the best of Spartan's knowledge, any shareholder holding sufficient securities of Spartan to materially affect the control of Spartan, 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.

Sanjib Gill

Mr. 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.

Penalties and Sanctions

No director, executive officer or shareholder holding a sufficient number of securities to affect materially the control of Spartan, within the last 10 years, has been subject to any penalties or sanctions imposed by a court or securities regulatory authority relating to trading in securities, promotion or management of a publicly traded issuer or theft or fraud.

Personal Bankruptcies

No director, executive officer or shareholder holding a sufficient number of securities to affect materially the control of Spartan, or a personal holding company of any such persons, 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.

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 2013, or of which any of its properties is the subject matter, or was the subject matter of in 2013, 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

There are no material interests, direct or indirect, of directors or executive officers of Spartan, of 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

Spartan has not entered into any material contracts within the most recently completed financial year, or before the most recently completed financial year which are still in effect other than in respect of the Arrangement and the Reorganization Agreement. See "*General Development of the Business – Recent Developments*" 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 MNP 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. MNP LLP is independent of Spartan in accordance with the rules of professional conduct of the Institute of Chartered 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
Reginald J. 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 has held senior executive positions in oil and gas issuers and has participated as a member of audit committees in the past.

Each director 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 issuer'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 (3)	All Other Fees(4)
December 31, 2013	63,000	-	-	38,500

Notes:

(1) The aggregate fees billed by the Corporation's auditor for audit fees.
(2) The aggregate fees billed for assurance and related services by the Corporation's auditor that are reasonably related to the performance of the audit or review of the Corporation's financial statements and are not disclosed in the "Audit fees" column.
(3) The aggregate fees billed for professional services rendered by the Corporation's auditor for tax compliance, tax advice, and tax planning.
(4) The aggregate fees billed for professional services rendered by the Corporation's auditor for acquisitions.

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 annual information form for the year ended December 31, 2012 dated December 11, 2013.

Additional financial information is provided for in Spartan's financial statements and management's discussion and analysis for the year ended December 31, 2013. Documents affecting the rights of securityholders, 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 500, 850- 2nd Street SW, Calgary, Alberta T2P 0R8, 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 Alexander Energy Ltd. (the "Corporation"):

1. We have evaluated of the Corporation's Reserves Data as at December 31, 2013. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2013, 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.

   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

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

4. The following table sets forth the estimated future net revenue attributed to proved plus probable reserves, estimated using forecast prices and costs on a before tax basis and calculated using a discount rate of 10 percent, included in the reserves data of the Corporation evaluated by us as of December 31, 2013, and identifies the respective portion thereof that we have audited, evaluated and reviewed 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 Alexander Energy Ltd. As of December 31, 2013, prepared December 2013 to February 2014	Canada				
Total			**Nil**	**33,400**	**Nil**	**33,400**

5. 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.

6. We have no responsibility to update the report referred to in paragraph 4 for events and circumstances occurring after its preparation date.

7. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

Executed as to our report referred to above:

Sproule Associated Limited
Calgary, Alberta
February 6, 2014

(signed) “*Richard A. Brekke*”

Richard A. Brekke, P. Eng.
Manager, Engineering and Partner

(signed) “*Victor Verkhogliad*”

Victor Verkhogliad, P. Geol.
Senior Petroleum Geologist and Partner

(signed) “*Alec Kovoltchuk”*

Alec Kovoltchuk, P. Geo.
Manager, Geoscience and Partner

(signed) “*Harry J. Helwerda”*

Harry J. Helwerda, P. Eng., FEC, FGC (Hon.)
President and Chief Executive Officer and Director

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 which are estimates of the proved reserves and probable reserves and related future net revenue as at December 31, 2013, estimated using forecast prices and costs.

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, 2013.

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. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

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

(signed) "*Michelle Wiggins*"
Michelle Wiggins
Chief Financial Officer

(signed) "*Reginald J. Greenslade*"
Reginald J. Greenslade
Director

(signed) "*Michael J. Stark*"
Michael J. Stark
Director

Dated April 30, 2014

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:

(a) 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;

(b) 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;

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

(d) 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, of 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. 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.