STORM RESOURCES LTD.

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2016

March 31, 2017

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DEFINITIONS

Unless the context indicates otherwise, the following terms shall have the meanings set out below when used in this AIF. Certain other terms and abbreviations used herein, but not defined herein, are defined in NI 51-101 or the COGE Handbook and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101 or the COGE Handbook.

"**2015 Grande Prairie Disposition**" has the meaning ascribed thereto under the heading "*General Development of the Business – Year Ended 2015*";

"**ABCA**" means the *Business Corporations Act* (Alberta);

"**AIF**" means this annual information form;

"**Audit Committee**" means the audit committee of the Board;

"**Board**" or "**Board of Directors**" means the board of directors of Storm;

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

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

"**Corporation**" or "**Storm**" means Storm Resources Ltd.;

"**Credit Facility**" means the $130,000,000 extendible revolving bank facility of the Corporation, as amended from time to time, based on the Corporation's producing reserves;

"**February 2014 Financing**" means the $29,725,000 bought deal short form prospectus financing of Common Shares and concurrent $5,125,000 non-brokered private placement of Common Shares which was completed on February 14, 2014;

"**HRB**" means the Horn River Basin in northeast British Columbia;

"**IFRS**" means International Financial Reporting Standards;

"**InSite**" means InSite Petroleum Consultants Ltd.;

"**InSite Report**" means the report prepared by and containing the evaluation of InSite of the oil, NGL and natural gas reserves attributable to the properties of the Corporation, in accordance with NI 51-101, dated February 24, 2017 and effective December 31, 2016;

"**June 2015 Financing**" means the $36,400,000 bought deal short form prospectus financing of Common Shares which was completed on June 10, 2015;

"**NEB**" means the National Energy Board;

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

"**SEO**" means Storm Exploration Inc.;

"**SGR**" means Storm Gas Resource Corp.;

"**SGR Arrangement**" means the acquisition of SGR pursuant to a plan of arrangement involving Storm, 1644140 Alberta Ltd., SGR and the holders of common shares of SGR completed on January 12, 2012;

"**Spectra**" means Spectra Energy;

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

"**Umbach Acquisition**" has the meaning ascribed thereto under the heading "*General Development of the Business - Year Ended 2014*"; and

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

Words importing the singular number only include the plural, and vice versa, and words importing any gender include all genders. The information set out in this AIF is stated as at December 31, 2016 unless otherwise indicated.

SELECTED ABBREVIATIONS

In this AIF, the abbreviations set forth below have the following meanings:

Oil and Natural Gas Liquids		**Natural Gas**	
Bbl	barrel	Bcf	billions of cubic feet
Bbls	barrels of oil or natural gas liquids	GJ	gigajoule
Bbls/d	barrels per day	Mcf	thousands of cubic feet
Mbbls	thousands of barrels	Mmcf	millions of cubic feet
Mboe	thousands of barrels of oil equivalent	Mcf/d	thousands of cubic feet per day
NGL	natural gas liquids	Mmbtu	millions of British Thermal Units

AECO-C	leading Canadian benchmark price for natural gas
AER	Alberta Energy Regulator
API	American Petroleum Institute
° API	is an indication of the specific gravity of crude oil measured on the API gravity scale. Liquid petroleum with a specific gravity of 28º API or higher is generally referred to as light crude oil
Boe	barrel of oil equivalent of natural gas and crude oil on the basis of 1 Boe for 6 (unless otherwise stated) Mcf of natural gas (this conversion factor is an industry accepted norm and is not based on either energy content or current prices)
Boe/d	barrel of oil equivalent per day
CCS	carbon capture and storage
GHG	greenhouse gas
OPEC	Organization of Petroleum Exporting Countries
$U.S.	United States dollar
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

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
Gigajoules	Mmbtu	0.949
Mmbtu	Gigajoules	1.055

CURRENCY

In this AIF, references to “dollars” and “$” are to the currency of Canada, unless otherwise indicated.

NON-IFRS MEASURES

Within this AIF, terms may be used which are not recognized under IFRS. Specifically, “netbacks”, “field operating netbacks”, “field operating netback including/excluding hedging”, “cash”, measurements “per commodity unit” and “per Boe” do not have any standardized meaning as prescribed by IFRS and are regarded as non-IFRS measures. These non-IFRS measures may not be comparable to the calculation of similar amounts for other entities and readers are cautioned that use of such measures to compare enterprises may not be valid. Non-IFRS terms are used to benchmark operations against prior periods and peer group companies and are widely used by investors, lenders, analysts and other parties. Field operating netbacks and field operating netbacks including/excluding hedging are common non-IFRS measurements applied in the oil and gas industry and are used by management to assess operational performance of assets. Field operating netbacks are calculated by deducting royalties, production and transportation expenses from revenue from product sales and are presented on a per-Boe basis.

NOTES ON RESERVES DATA AND OTHER OIL AND NATURAL GAS INFORMATION

Caution Respecting Reserves Information

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

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

Caution Respecting Boe

In this AIF, the abbreviation Boe means barrel of oil equivalent on the basis of 1 Boe to 6 Mcf of natural gas when converting natural gas to Boe. Boe may be misleading, particularly if used in isolation. A Boe conversion ratio of 6 Mcf to 1 Boe is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Reserves Categories

(a) “**reserves**” are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on (a) analysis of drilling, geological, geophysical, and engineering data; (b) the use of established technology; and (c) specified economic conditions, which are generally accepted as being reasonable and shall be disclosed. Reserves are classified according to the degree of certainty associated with the estimates.

(b) “**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.

(c) “**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.

(d) "**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.

(e) "**undeveloped**" reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (e.g., when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved and 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 sub-divide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

(f) "**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.

Levels of Certainty for Reported Reserves

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

- For proved reserves, at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimation; and

- For proved plus probable reserves, at least a 50 percent probability that the quantities actually recovered will equal or exceed the estimation.

A quantitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the 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 Definitions

The following terms, used in the preparation of the InSite Report in accordance with NI 51-101 and this AIF, have the following meanings:

(a) "**abandonment and reclamation costs**" means all costs associated with the process of restoring a reporting issuer's property that has been disturbed by oil and gas activities to a standard imposed by applicable government or regulatory authorities;

(b) "**crude oil**" or "**oil**" means a mixture that consists mainly of pentanes and heavier hydrocarbons, which may contain sulphur and other non-hydrocarbon compounds, that is recoverable at a well from an underground reservoir and that is liquid at the conditions under which its volume is measured or estimated. It does not include solution gas or NGL.

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

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

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

(ii) drill and equip development wells, development type stratigraphic test wells;

(iii) service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and the wellhead assembly;

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

(v) provide improved recovery systems.

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

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

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

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

(iii) costs of dry holes;

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

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

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

(h) "**field**" means an area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impervious strata or laterally by local geologic barriers, or both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to denote localized geological features, in contrast to broader terms such as "basin", "trend", "province", "play" or "area of interest".

(i) "**future income tax expenses**" means future income tax expenses estimated (generally, year-by-year):

(i) making appropriate allocations of estimated unclaimed costs and losses carried forward for tax purposes, between oil and gas activities and other business activities;

(ii) without deducting estimated future costs that are not deductible in computing taxable income;

(iii) taking into account estimated tax credits and allowances; and

(iv) applying to the future pre-tax net cash flows relating to the Corporation's oil and gas activities the appropriate year-end statutory tax rates, taking into account future tax rates already legislated.

(j) "**future net revenue**" means a forecast of revenue, estimated using forecast prices and costs or constant prices and costs, arising from the anticipated development and production of resources, net of the associated royalties, operating costs, development costs, and abandonment and reclamation costs.

(k) "**gross**" means:

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

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

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

(l) "**light crude oil**" means crude oil with a relative density greater than 31.1 degrees API gravity;

(m) "**medium crude oil**" means crude oil with a relative density greater than 22.3 degrees API gravity and less than or equal to 31.1 degrees API gravity;

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

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

(p) "**net**" means:

(i) in relation to the Corporation's interest in production or reserves, its working interest (operating or non-operating) share after deduction of royalty obligations, plus its royalty interests in production or reserves;

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

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

(q) "**operating costs**" or "**production costs**" means costs incurred to operate and maintain wells and related equipment and facilities, including applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities.

(r) "**production**" means recovering, gathering, treating, field or plant processing (for example, processing gas to extract NGL) and field storage of oil and natural gas from wellbores.

(s) "**property**" includes:

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

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

(iii) an agreement with a foreign government or authority under which the Corporation participates in the operation of properties or otherwise serves as "producer" of the underlying reserves (in contrast to being an independent purchaser, broker, dealer or importer).

A property does not include supply agreements, or contracts that represent a right to purchase, rather than extract, oil or gas.

(t) "**property acquisition costs**" means costs incurred to acquire a property (directly by purchase or lease, or indirectly by acquiring another corporate entity with an interest in the property), including:

(i) costs of lease bonuses and options to purchase or lease a property;

(ii) the portion of the costs applicable to hydrocarbons when land including rights to hydrocarbons is purchased in fee; and

(iii) brokers' fees, recording and registration fees, legal costs and other costs incurred in acquiring properties.

(u) "**proved property**" means a property or part of a property to which reserves have been specifically attributed.

(v) "**reservoir**" means a porous and permeable underground formation containing a natural accumulation of producible oil or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

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

(x) "**solution gas**" means natural gas dissolved in crude oil.

(y) "**stratigraphic test well**" means a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Ordinarily, such wells are drilled without the intention of being completed for hydrocarbon production. They include wells for the purpose of core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic test wells are classified as (i) "exploratory type" if not drilled into a proved property; or (ii) "development type", if drilled into a proved property. Development type stratigraphic wells are also referred to as "**evaluation wells**".

(z) "**support equipment and facilities**" means equipment and facilities used in oil and gas activities, including seismic equipment, drilling equipment, construction and grading equipment, vehicles, repair shops, warehouses, supply points, camps, and division, district or field offices.

(aa) "**unproved property**" means a property or part of a property to which no reserves have been specifically attributed.

(bb) "**well abandonment costs**" means costs of abandoning a well (net of salvage value) and of disconnecting the well from the surface gathering system. They do not include costs of abandoning the gathering system or reclaiming the wellsite.

FORWARD-LOOKING STATEMENTS

Certain information set forth in this AIF, including management's assessment of Storm's future plans and operations specifically in relation to 2017 and 2018, contains forward-looking information (within the meaning of applicable Canadian securities legislation). Such statements or information are generally identifiable by words such as "anticipate", "believe", "intend", "plan", "expect", "estimate", "budget", "forecast", "would", "could", "will", "may", "future" or other similar words and include statements relating to or associated with individual wells, facilities, regions or projects as well as timing of any future event which may have an effect on the Corporation's operations or financial position. Any statements regarding the following are forward-looking statements:

- the performance characteristics of the Corporation's natural gas and NGL properties;
- future market prices and costs of and supply and demand for crude oil, NGL and natural gas prices;
- future gains or losses from commodity price contracts;
- future production volumes in 2017 and 2018, production volumes by commodity and production declines;
- the size of the natural gas and NGL reserves of the Corporation and anticipated future funds flow from such reserves;
- future revenues and costs (including royalties) and revenues and costs per commodity unit;
- future capital expenditures and their allocation to specific exploration and development activities or periods, particularly with respect to the number of wells to be drilled as part of the 2017 capital program;
- future drilling, completion and tie-in of wells;
- future facility access, acquisition or construction and entry in service and timing thereof;
- future pipeline capacity;
- future funds flow including per-share amounts;
- future earnings or losses including per-share amounts;
- future IFRS and non-IFRS measurements;
- future sources of funding for capital programs and future availability of such sources;
- future asset acquisitions or dispositions;
- intentions with respect to investments;
- future decommissioning costs, inflation rates and discount rates used to determine the net present value of such costs;
- future abandonment and reclamation costs;
- development plans for Storm's Umbach and HRB properties;
- future debt levels including working capital deficiency;
- future availability and terms of financing, including credit facilities;
- future tax liabilities and future use of tax pools and losses;
- measurement and recoverability of reserves or contingent resources and timing of such recoverability;
- estimates of ultimate recovery from wells;
- future finding and development costs, production costs, transportation costs, interest and financing costs, and general and administrative costs, in total and by commodity unit;

- treatment under governmental regulatory regimes and tax and royalty laws;
- estimates of the future life of depreciable assets;
- future charges for depletion, depreciation and accretion;
- future interest rates;
- estimates on a per-share basis and per-Boe basis;
- future effect of regulatory regimes and tax and royalty laws, including incentive programs;
- effect of existing or future contractual obligations including agreements pertaining to processing, transportation and marketing of natural gas, condensate and NGL, specifically a reduction of production costs as a result of the Spectra agreement effective January 1, 2017;
- future availability and cost of drilling rigs, completion and tie-in services and other oilfield services;
- dates or time periods by which wells will be drilled, completed and tied in, facility and pipeline construction completed and brought into service, geographical areas developed, facilities and pipelines accessed, including twinning of the third field compression facility; and
- changes to any of the foregoing.

With respect to forward looking statements contained in this AIF, the Corporation has made assumptions regarding:

- natural gas and NGL production levels;
- the success of the Corporation's operations and exploration and development activities;
- prevailing climatic conditions, commodity prices, interest and exchange rates;
- the availability of capital to fund planned expenditures;
- timing and amount of capital expenditures;
- general economic and financial market conditions;
- the success, nature and timing of enhanced recovery activities;
- the ability of the Corporation to secure necessary personnel, equipment and services;
- government regulation in the areas of taxation, royalty rates and environmental protection;
- the success of exploration and development activities; and
- access to market for the Corporation's production.

The forward-looking statements are subject to known and unknown risks and uncertainties and other factors which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Such factors include:

- industry conditions, including commodity prices;
- pipeline and third party facility capacity constraints and access to sales markets;
- volatility of commodity prices;
- currency fluctuations;
- imprecision of reserve estimates and related costs including royalties, production costs and future development costs;
- environmental risks;
- stock market volatility;
- ability to access sufficient capital from internal and external sources and the ability of the Corporation to realize value from acquired assets and corporations;
- credit facility risks;
- failure to realize anticipated benefits of acquisitions and dispositions;
- physical and operational risks inherent in oil and natural gas field activity;
- inability to secure labour, services or equipment on a timely basis or on favourable terms;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- unfavourable weather conditions;
- incorrect assessments of the value of acquisitions and exploration and development programs;
- success of drilling programs;

- geological, technical, drilling, completion and processing problems;
- results of enhanced recovery responses;
- changes in legislation, including changes in tax laws and incentive programs relating to the oil and gas industry; and
- the other factors discussed under "*Risk Factors*".

All of these caveats should be considered in the context of current economic conditions, in particular volatility in commodity prices, enduring sub-economic prices for crude oil and natural gas, the attitude of lenders and investors towards natural gas assets, the condition of financial markets generally, as well as the stability of joint venture and other business partners, all of which are outside the control of Storm.

Ultimate recovery of reserves is based on forecasts of future results, estimates of amounts not yet determinable and assumptions by management of Storm.

Statements relating to "reserves" or "resources" are forward-looking statements, including financial measurements such as net present value, as they involve the assessment, based on estimates and assumptions, that the reserves and resources described exist in the quantities predicted or estimated, and can be profitably produced in the future.

Readers are advised that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements. Storm disclaims any intention or obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise, except as required under securities law.

References to forward-looking information are made elsewhere in this AIF. The forward-looking statements contained herein are expressly qualified by this cautionary statement.

THE CORPORATION

Storm Resources Ltd. was incorporated under the ABCA on June 8, 2010 under the name of "1541229 Alberta Ltd.". On July 30, 2010, the Corporation filed articles of amendment to change its name to "Storm Resources Ltd.". On March 23, 2012, the Corporation filed articles of amalgamation following a corporate acquisition.

Storm is a reporting issuer (or the equivalent thereof) in each of the provinces of Canada. On August 31, 2010, the Common Shares were listed and posted for trading on the TSXV under the symbol "SRX".

As of March 31, 2017, the Corporation has one subsidiary, SGR, which is wholly-owned and was incorporated under the ABCA.

The Corporation's registered office is located at 4000, 421 - 7th Avenue S.W., Calgary, Alberta, T2P 4K9, and its head and principal office is located at 200, 640 – 5th Avenue S.W., Calgary, Alberta, T2P 3G4.

GENERAL DEVELOPMENT OF THE BUSINESS

Year-Ended 2014

On January 31, 2014, Storm completed the acquisition of a 100% working interest in 29 sections of land in the Umbach-Nig area prospective for liquids rich natural gas from the Montney formation which included two producing horizontal wells (the "**Umbach Acquisition**"). Consideration for the Umbach Acquisition totaled $87.9 million and consisted of: (i) the payment of $30.0 million in cash to the vendor; and (ii) the issuance of 13,629,442 Common Shares at a deemed issuance price of $4.25 per Common Share to the vendor.

On February 14, 2014, Storm completed the February 2014 Financing, which consisted of: (i) a bought deal financing by way of short form prospectus pursuant to which Storm, through a syndicate of underwriters, issued an aggregate of 7,250,000 Common Shares at a price of $4.10 per Common Share for aggregate gross proceeds of $29,725,000; and (ii) a non-brokered private placement financing of 1,250,000 Common Shares at a price of $4.10 per Common Share to certain investors, including insiders, identified by Storm for aggregate gross proceeds of $5,125,000.

In 2014, Storm drilled 17 wells (17.0 net) with a 100% success rate. These wells included 16 horizontal wells (16.0 net) and one vertical well (1.0 net) in the Montney formation at Umbach and 13 horizontal wells (12.6 net) were completed. In addition, a second field compression facility was constructed with initial capacity of 24 Mmcf per day. The total cost of construction was approximately $15.3 million and the facility began operating on August 19, 2014.

Year-Ended 2015

On June 10, 2015, Storm completed the June 2015 Financing, which was a bought deal financing by way of short form prospectus pursuant to which Storm, through a syndicate of underwriters, issued an aggregate of 8,000,000 Common Shares at a price of $4.55 per Common Share for aggregate gross proceeds of $36.4 million.

On July 15, 2015, Storm completed the disposition of properties in the Grande Prairie area of northwest Alberta, with production prior to sale of approximately 500 Boe/d, for proceeds of $24.0 million (the "**2015 Grande Prairie Disposition**"). The net proceeds of the 2015 Grande Prairie Disposition were applied to reduce Storm's bank debt. The effective date of the 2015 Grande Prairie Disposition was July 1, 2015. Following the 2015 Grande Prairie Disposition, the remaining Alberta assets of Storm consist of one property in the Valhalla area. The disposition resulted in the sale of all of Storm's reserves of crude oil.

In December 2015, Storm began to diversify natural gas sales away from BC Station 2 with the start of firm service on the Alliance Pipeline to Chicago. Contracted capacity increases from 43 Mmcf per day in 2016 to 53 Mmcf per day in 2018.

In 2015, Storm drilled 10 horizontal wells (10.0 net) in the Montney formation at Umbach with a 100% success rate and 13 horizontal wells (13.0 net) were completed. At year end there was an inventory of six drilled wells which included two completed wells. The second field compression facility was expanded to 62 Mmcf per day and a condensate stabilizer, a fuel gas conditioning unit and equipment for salt water disposal were also added, for an investment totaling $23.5 million.

Year-Ended 2016

During 2016, construction of a third field compression facility at Umbach began, with the facility completed in January 2017, expanding Storm's compression capacity to 115 Mmcf per day. The total cost of construction is estimated to be approximately $25 million with $24 million incurred to the end of 2016 and the remaining $1 million incurred in January 2017. The new facility will be twinned in due course at an incremental cost of approximately $7 million bringing compression capacity to 150 Mmcf per day. The third compression facility began operating in January 2017.

In September 2016, Storm entered into a natural gas processing arrangement at Umbach with Spectra that has an effective date of January 1, 2017 and a total commitment of 65 Mmcf per day of raw gas at terms ranging from 5 to 15 years. It is expected this arrangement will reduce operating costs by 15% to 20% and support future growth. The arrangement includes an option to increase contracted capacity while providing for continued diversification of natural gas sales with access to three sales pipelines through the McMahon Gas Plant (Alliance Pipeline to Chicago, TransCanada NGTL system to AECO, Spectra T-north mainline to BC Station 2).

At the beginning of 2016, Storm had an inventory of six standing wells, of which four awaited completion. Twelve wells (12.0 net) were drilled in the year in the Montney formation at Umbach with 10 wells (10.0 net) being completed. Nine wells were brought on production, resulting in an inventory of nine drilled wells with six awaiting completion at the end of 2016.

The InSite Report assigned gross proved plus probable reserves as at December 31, 2016 in the amount of 104,192 Mboe, a year-over-year increase of 3%. Storm's undeveloped lands totaled 239,255 net acres at the end of 2016. See "*Statement of Reserves Data and Other Oil and Gas Information*".

DESCRIPTION OF THE BUSINESS

General

Storm is engaged in the exploration for, and the acquisition, development and production of natural gas and NGL reserves in the provinces of Alberta and British Columbia. The Corporation focuses on a selective combination of exploratory and development drilling, along with strategic asset and corporate acquisitions where the Corporation believes further exploration and exploitation opportunities exist. Storm's main areas of activity are located onshore in the Umbach and HRB areas of northeast British Columbia, with minor interests in the Valhalla area of north central Alberta.

Storm's business objective involves the identification and exploitation of opportunities to develop natural gas and NGL assets profitably in Western Canada. The Corporation uses a number of strategies to manage the operational and financial risks associated with this objective including a strong geographical and geological focus to its operations, the generation of its own prospects, ownership of its facilities and operatorship of its assets wherever possible.

Although the Corporation favours a 100% working interest in its properties, it will accept a lower working interest in circumstances where capital requirements exceed either the Corporation's funding capacity or its tolerance for risk.

The Corporation looks to acquire assets in areas with which it is familiar, provided that the acquired assets come at a price competitive with the Corporation's internal finding and development costs and/or are strategic to the Corporation's continued growth and expansion.

Management of the Corporation combines a growth oriented operating philosophy with a disciplined approach to capital investment, based on funding the Corporation's capital investment out of funds flow, debt (within an acceptable multiple of funds flow), selective asset dispositions and, in appropriate circumstances, the issuance of equity. In certain circumstances, the Corporation will temporarily exceed internal debt guidelines to complete an acquisition, or a seasonally oriented drilling program or a major addition to facilities. However, debt reduction programs are then initiated to bring debt within acceptable levels. Hedging may be used as part of a debt management program to stabilize funds flow through the use of instruments such as fixed price sales of commodities, pricing collars, interest rate swaps, fixing of foreign currency exchange rates, fixing of index differentials and similar. Entering into hedging arrangements is subject to compliance with the Corporation's hedging policy which requires the approval of the Board of Directors.

The Corporation focuses on management of costs, both capital and operating. A low cost structure means that the Corporation can continue to execute its business plan and grow in periods of low commodity prices, particularly for natural gas in the last several years, and more recently, for NGL, and thus protect its competitive position.

Competitive Conditions

The Corporation actively competes for reserve acquisitions, exploration leases, licences and concessions, equipment and skilled industry personnel with a large number of other oil and gas companies, many of which have significantly greater financial resources than the Corporation. The

Corporation's competitors include major integrated oil and natural gas companies and numerous other independent oil and natural gas companies of varying sizes.

The Corporation's ability to continue to bid on and acquire additional property rights, to discover and produce reserves, to participate in drilling opportunities, to construct and operate production facilities and to identify and enter into advantageous commercial arrangements is dependent upon (i) the Corporation developing and maintaining close working relationships with its industry partners; (ii) its ability to select and evaluate suitable properties for acquisition and development; (iii) its ability to consummate commercially attractive transactions in a competitive environment; and (iv) the maintenance of adequate financial capacity.

Cyclical Nature of Business

Storm's key properties, with the exception of the HRB in northeast British Columbia, generally provide year round access, enabling (subject to the imposition of seasonal road closures) drilling and other wellsite activities to continue throughout the year. In 2016, approximately 64% of Storm's revenue was generated from the sale of natural gas, with 36% coming from the sale of condensate and NGL.

North American natural gas pricing is dependent on a wide range of factors, such as drilling activity, storage levels, supply increases from newly developed reserves, as well as demand, which is weather sensitive and peaks during the cold winter months. This can result in significant price volatility. In particular, since 2009, natural gas markets in North America have seen deliveries of increasing volumes of natural gas from shale deposits in the United States, exploitation of which in recent years has been facilitated by improvements in drilling and fracturing technologies. Production of natural gas from shale is characterized by very high initial rates, followed by rapid declines with the consequence being that natural gas markets in recent years have in part been supplied with gas from new wells with high initial deliverability.

Oil and NGL prices have also fluctuated greatly during recent years and are determined by global supply and demand factors, including weather and general economic conditions, competition from other oil and natural gas producing regions, pipeline access and geopolitical circumstances. The latter circumstance emerged late in 2014, continued through 2015 and 2016 and to date in 2017, resulting in severely reduced prices for crude oil and for condensate which is priced with reference to crude oil.

Since 2013, the Corporation has primarily focused on high condensate and NGL content natural gas prospects in the Umbach area of northeast British Columbia.

Environmental Protection Requirements

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to evolving international conventions and national, provincial and municipal laws and regulations. Environmental legislation provides for, inter alia, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and 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 may result in the imposition of fines and penalties, some of which may be material, as well as the modification or cancellation of operating licences and permits including suspension of production. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines, increased potential for 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 the Corporation to incur costs to remedy such discharge and compensate affected third parties in the event that they are not covered by the Corporation's insurance. Enforcement of increasingly stringent environmental laws may potentially 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, capital expenditures, results of operations and competitive position or prospects. The application of environmental regulation to unrelated parties may also affect the operations of the Corporation, resulting, for example, in pipeline or facility closures or curtailments.

In the United States, and to a lesser extent in Canada, there has been considerable public concern that new fracturing technologies, which have resulted in exploitation of natural gas and crude oil in shale and similar formerly sub-economic deposits, can introduce chemicals or hydrocarbons to or otherwise damage or pollute surface water or underground water tables used to meet water demand in populated areas. The evolution of this concern is not foreseeable at this time. Nonetheless, the Corporation's properties at Umbach and the HRB involve exploitation of natural gas using fracturing technologies and it is possible that the Corporation will be subject to additional environmental controls, the future effect of which on the Corporation's operations cannot be determined at present.

In December 2015, Canada adopted the Paris Agreement at the 21st United Nations Climate Change Conference ("**COP 21**") held in Paris, France. The goal of the Paris Agreement is to cut global GHG emissions and implement actions to mitigate and adapt to climate change impacts. Specifically, countries pledged to reduce GHG emissions in order to cap the rise in global temperatures at well below 2 degrees Celsius and even pursue efforts to limit the temperature increase to 1.5 degrees Celsius.

The Paris Agreement is a significant departure from the 2009 Copenhagen Accord, and contains a number of binding and non-binding commitments, including a long-term emissions goal of peaking global greenhouse gas "as soon as possible" to achieve balance between anthropogenic emissions by sources and removal of GHG emissions by sinks in the second half of the century. This means reaching net zero emissions after 2050; however, there is no corresponding timeline or details about how the delayed peak by developing countries will be balanced. In 2018, Canada along with the other member parties will convene a facilitative dialogue to assess their collective efforts in relation to their progress towards the long-term goal. The outcomes of this dialogue will likely inform future climate policies and actions.

Since national pledges to reduce emissions are voluntary, the success of the pact in achieving meaningful GHG emission reductions will likely turn on the willingness of future governments to take action as well as global peer pressure. Ahead of COP 21, countries were invited to submit their Intended Nationally Determined Contributions (INDCs), which set out what post-2020 climate actions they intend to take under a new international climate agreement. Prior to adopting the Paris Agreement, Canada set an INDC target of a 30% reduction from 2005 levels in GHG emissions by 2030.

It is uncertain what effect this action will have on the long and medium term business of the Corporation. However, recent changes in government, both federally and provincially, may result in public policy evolving in a fashion more accommodating to the intent of the Paris Agreement. Further, there is considerable and increasing opposition, both domestic and international, to the extraction of crude oil from oilsands in Alberta which may have an indirect effect on the Corporation's operations as oilsands operations use natural gas as an energy source and certain NGL are used as a diluent when crude oil from oilsands is pipelined. The uncertainty surrounding the construction of the Keystone XL Pipeline and opposition to expanding the Trans Mountain Pipeline to tidewater, if successful, may result in the industry being unable to access international markets for its products.

Despite having been previously rejected, the Keystone XL Pipeline project may proceed following TransCanada's re-submission of its application for a presidential permit on January 26, 2017 and subsequent approval of such permit by the US State Department on March 24, 2017.

See also "*Industry Conditions*".

Specialized Skill and Knowledge

Exploration for and the acquisition, development of and production of oil, natural gas and NGL reserves requires specialized skills and knowledge in the areas of petroleum engineering, geophysics, geology, facility construction and land title. The Corporation has personnel with the required specialized skills and knowledge. While the labour market in the industry is periodically highly competitive, the Corporation expects to be able to attract and retain appropriately qualified employees throughout 2017.

Renegotiation or Termination of Contracts

Within the knowledge of management, the Corporation is not a party to any material contract that may be subject to renegotiation or termination in 2017.

Employees

As of December 31, 2016, the Corporation had 24 full-time employees, 4 part-time employees and one consultant.

MANAGEMENT OF THE CORPORATION

As at the date hereof, the name, municipality of residence and principal occupation of the directors and senior officers of the Corporation are as follows:

Name and Municipality of Residence	Position Held	Date First Elected or Appointed as Director[5]
Brian Lavergne Calgary, Alberta	President, Chief Executive Officer and Director	June 8, 2010
Donald G. McLean Calgary, Alberta	Chief Financial Officer	-
Robert S. Tiberio Calgary, Alberta	Chief Operating Officer	-
Jamie P. Conboy Calgary, Alberta	Vice President, Geology	-
John J. Devlin Calgary, Alberta	Vice President, Finance	-
H. Darren Evans Calgary, Alberta	Vice President, Exploitation	-
Bret A. Kimpton Calgary, Alberta	Vice President, Production	-
Matthew J. Brister[2][3] Calgary, Alberta	Director	June 8, 2010
John A. Brussa Calgary, Alberta	Director	June 8, 2010
Mark A. Butler[1][2][4] Calgary, Alberta	Director	June 8, 2010
Stuart G. Clark[1] Calgary, Alberta	Chairman and Director	June 8, 2010
Gregory G. Turnbull, QC[3] Calgary, Alberta	Director	June 8, 2010
P. Grant Wierzba[2][3] Calgary, Alberta	Director	June 8, 2010
James K. Wilson[1][4] Calgary, Alberta	Director	June 8, 2010

Notes:

(1) Member of the Audit Committee.
(2) Member of the Compensation, Governance and Nomination Committee.

(3) Member of the Reserves Committee.
(4) Holds ICD.D director certification from the Institute of Corporate Directors.
(5) The directors will hold office until the next annual meeting of holders of Common Shares or until their successor is duly elected or appointed, unless their office is earlier vacated in accordance with the By-laws.

As at the date hereof, the officers and directors, as a group, held, directly or indirectly, or exercise control or direction over 16,614,320 Common Shares representing approximately 13.7% of the issued and outstanding Common Shares.

Each of Messrs. Lavergne, McLean, Tiberio, Conboy, Devlin, Evans and Kimpton devotes his full time and attention to the business and affairs of Storm. The remaining directors of Storm devote their time and attention to the affairs of Storm only as required. Profiles of Storm's directors and officers and the particulars of their respective principal occupations during the previous five years as of March 31, 2017 are set forth below.

Brian Lavergne, President, Chief Executive Officer and Director

Mr. Lavergne has been the President and Chief Executive Officer and a director of Storm since June 8, 2010. Prior thereto, Mr. Lavergne was the President and Chief Executive Officer and a director of SEO from June 2004 to August 17, 2010. Mr. Lavergne holds a Bachelor of Science in Mechanical Engineering from the University of Alberta.

Donald G. McLean, Chief Financial Officer

Mr. McLean is a Chartered Accountant and has been the Chief Financial Officer of Storm since June 8, 2010. Prior thereto, Mr. McLean was Vice President, Finance and Chief Financial Officer of SEO from June 2004 to August 17, 2010.

Robert S. Tiberio, Chief Operating Officer

Mr. Tiberio has been the Chief Operating Officer of Storm since August 18, 2010. Prior thereto, Mr. Tiberio was Chief Operating Officer of SEO from June 2004 to August 17, 2010.

Jamie P. Conboy

Mr. Conboy was appointed Vice President, Geology of Storm on May 1, 2015. Prior thereto, he held the position of Chief Geologist at Storm since August 17, 2010.

John J. Devlin, Vice President, Finance

Mr. Devlin was appointed Vice President, Finance of Storm on March 3, 2011. Prior thereto, Mr. Devlin was the Controller of Storm from August 18, 2010 to March 3, 2011. Mr. Devlin was the Controller of SEO from January 2005 until August 17, 2010.

H. Darren Evans

Mr. Evans was appointed Vice President, Exploitation on May 1, 2015. Prior thereto, he held the position of Engineering Manager at Storm since August 17, 2010.

Bret A. Kimpton

Mr. Kimpton was appointed Vice President, Production on May 1, 2015. Prior thereto, he held senior engineering positions within the organization progressing from Senior Production Engineer to Production Manager.

Matthew J. Brister, Director

Mr. Brister is a director and Chairman of the Board of Chinook Energy Inc. and was President and Chief Executive Officer of Chinook Energy Inc. until December 31, 2013. Mr. Brister was a director of SEO from May 2008 until August 17, 2010. Mr. Brister holds a Bachelor of Science in Geology from the University of Calgary.

John A. Brussa, Director

Mr. Brussa is Chairman and a partner at Burnet, Duckworth & Palmer LLP, a law firm specializing in the energy sector, where he is the head of the Tax Department. He sits on the board of a number of public and private corporations in the energy, energy services, financial and marketing sectors. Mr. Brussa was a director of SEO.

Mark A. Butler, Director

Mr. Butler is an independent businessman and was a director of SEO. Mr. Butler is the past CEO of WestPac LNG Corporation, an early stage private capital entrant into the development of LNG facilities in British Columbia. Mr. Butler holds a Bachelor of Laws degree from the University of Saskatchewan, a Masters of Business Administration from the University of Calgary, and ICD.D director certification from the Institute of Corporate Directors.

Stuart G. Clark, Chairman and Director

Mr. Clark has been a director and Chairman of Storm since June 8, 2010. Mr. Clark was a director of SEO from June 2004 to August 17, 2010. Mr. Clark served as a director and Chairman of Rock Energy Inc. from January 2004 to July 2016 and has been a director of Chinook Energy Inc. since June 2009. Mr. Clark was a director of Bellamont Exploration Ltd. from November 2009 to March 2012. Mr. Clark also serves as a director of a number of private companies. Mr. Clark is a retired businessman and holds a Bachelor of Commerce (Honours) from the University of Manitoba.

Gregory G. Turnbull, QC, Director

Mr. Turnbull is a senior partner at McCarthy Tétrault LLP, which he joined in July, 2002. Mr. Turnbull was a director of SEO. Mr. Turnbull is currently a director of a number of public and private corporations, largely associated with the energy industry.

P. Grant Wierzba, Director

Mr. Wierzba is a director of Chinook Energy Inc. and was Vice President, Operations until December 31, 2013. Mr. Wierzba was a director of SEO. Mr. Wierzba holds a Bachelor of Science in Engineering from the University of Alberta.

James K. Wilson, Director

Mr. Wilson has been a director of Storm since June 8, 2010. Prior thereto, he was a director of SEO from February 2010 until August 17, 2010. Since September 2015, he has been the Chief Financial Officer and Corporate Secretary of Aspenleaf Energy Limited. From October 2010 to October 2011 and from February 2013 to September 2015, he was the Managing Director of Walwil Resources Ltd., an oil and gas financial consulting company. From October 2011 to February 2013, Mr. Wilson was Chief Financial Officer of Mako Hydrocarbons Ltd., a public junior oil and gas company. Mr. Wilson maintains memberships in the Institute of Corporate Directors, Financial Executives International of Canada and Chartered Professional Accountants of Alberta. Mr. Wilson holds a Bachelor of Commerce degree from the University of Calgary, Chartered Accountant designation and ICD.D director certification from the Institute of Corporate Directors.

Corporate Cease Trade Orders or Bankruptcies

To the knowledge of management of the Corporation, other than as set forth below, there has been no director or officer, or any shareholder holding a sufficient number of securities of the Corporation to affect materially the control of the Corporation, that is, or within the 10 years before the date of this AIF has been, a director or officer of any other issuer that:

(a) while that person was acting in that capacity, was the subject of a cease trade or similar order, or an order that denied the other issuer access to any exemptions under Canadian securities legislation, that was in effect for a period of more than 30 consecutive days; or

(b) while that person was acting in that capacity, was subject to an event that resulted, after the director or executive officer ceased to be a director or executive officer, in the other issuer being the subject of a cease trade or similar order or an order that denied the relevant company access to any exemption under securities legislation, that was in effect for a period of more than 30 consecutive days; or

(c) 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.

Mr. Gregory G. Turnbull, a director of the Corporation, was a director 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. Turnbull resigned as a director immediately thereafter. In addition, Mr. Turnbull was a director of Sonde Resources Corp., a Canada-based diversified global energy company, which filed for bankruptcy on February 2, 2015. Mr. Turnbull resigned as a director on March 27, 2014. Mr. Turnbull resigned as a director of Porto Energy Corp. on May 30, 2014 following the decision by Porto Energy Corp.'s directors and management to wind-up Porto Energy Corp.'s operations due to capital constraints. Porto Energy Corp. has subsequently become subject to cease trade orders for failure to file periodic disclosure (interim financial filings) and such cease trade orders remain in effect.

Mr. John A. Brussa, a director of the Corporation, resigned as a director of Calmena Energy Services Inc. ("**Calmena**") on June 30, 2014. On January 19, 2015, a senior lender of Calmena (the "**Senior Lender**") made an application to the Court of Queen's Bench of Alberta (the "**Court**") to appoint an interim receiver under the *Bankruptcy and Insolvency Act* (Canada) and trading in the common shares of Calmena was suspended by the Toronto Stock Exchange. On January 20, 2015, the Senior Lender was granted a receivership order by the Court.

Mr. Brussa was also a director of Enseco Energy Services Corp. ("**Enseco**"), a public oilfield service company, which was placed in receivership on October 14, 2015 and, in connection therewith, a receiver was appointed under the *Bankruptcy and Insolvency Act* (Canada). Mr. Brussa resigned as a director of Enseco on October 14, 2015. On December 21, 2015, Enseco was assigned into bankruptcy by the receiver.

Mr. Brussa was a director of Argent Energy Ltd. which was the administrator of Argent Energy Trust. On February 17, 2016, Argent Energy Trust and its Canadian and United States holding companies (collectively, "**Argent**") commenced proceedings under the *Companies' Creditors Arrangement Act* ("**CCAA**") for a stay of proceedings until March 19, 2016. On the same date, Argent filed voluntary petitions for relief under Chapter 15 of the *United States Bankruptcy Code* ("**Chapter 15**"). On March 9, 2016, the stay of proceedings under the CCAA was extended until May 17, 2016. Additionally, on March 10, 2016, the U.S. Bankruptcy Court approved an order recognizing the CCAA as the foreign main proceedings under Chapter 15. Mr. Brussa resigned as a director of Argent Energy Ltd. on June 30, 2016.

Mr. Brussa resigned as a director of Twin Butte Energy Ltd. ("**Twin Butte**") on September 1, 2016. On September 1, 2016, the senior lenders of Twin Butte (the "**Senior Lenders**") made an application to the Court of Queen's Bench of Alberta (the "**Court**") to appoint a receiver and manager over the assets, undertakings and property of Twin Butte under the *Bankruptcy and Insolvency Act* (Canada) and trading in the common shares of Twin Butte was suspended by the Toronto Stock Exchange. On September 1, 2016, the Senior Lenders were granted a receivership order by the Court.

Mr. Brussa was a director of Virginia Hills Oil Corp. ("**VHO**"), a TSX-V listed oil and gas company. On February 13, 2017, VHO received a demand notice and notice of intention to enforce security from its lenders and agreed to consent to the early enforcement of the lenders' security and the appointment of a receiver over all of the current and future assets, undertakings and properties of VHO. The receiver was appointed on February 13, 2017. Mr. Brussa resigned as a director of VHO on February 24, 2017.

Penalties or Sanctions

To the knowledge of management of the Corporation, no director or officer, or any shareholder holding a sufficient number of securities of the Corporation to affect materially the control of the Corporation, has:

(a) been subject to any penalties or sanctions imposed by a court relating to Canadian securities legislation or by a Canadian securities regulatory authority or has entered into a settlement agreement with a Canadian securities regulatory authority; or

(b) been subject to any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

Personal Bankruptcies

To the knowledge of management of the Corporation, there has been no director or officer, or any shareholder holding sufficient number of securities of the Corporation to affect materially the control of the Corporation, or a personal holding company of any such person that has, within the 10 years before the date of this AIF, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or was subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director or officer.

Conflicts of Interest

Circumstances may arise where members of the Board of Directors are directors or officers of corporations which are in competition to the interests of Storm. No assurances can be given that opportunities identified by such Board members in the context of their relationship with another corporation will be provided to Storm. Pursuant to the ABCA, directors who have an interest in a proposed transaction upon which the Board of Directors is voting are required to disclose their interests and refrain from voting on the transaction.

Mr. John A. Brussa, a director of the Corporation, is Chairman and a partner of Burnet, Duckworth & Palmer LLP, a law firm that provides legal services to Storm. The Board of Directors does not believe that any of the activities undertaken by Mr. Brussa or by Burnet, Duckworth & Palmer LLP interfere, or could be perceived to interfere, in any material way with his ability to act with a view to the best interests of Storm.

Mr. Gregory G. Turnbull, a director of the Corporation, is a partner of McCarthy Tétrault LLP, a law firm that provides legal services to Storm. The Board of Directors does not believe that any of the activities undertaken by Mr. Turnbull or by McCarthy Tétrault LLP interfere, or could be perceived to interfere, in any material way, with his ability to act with a view to the best interests of Storm.

Legal Proceedings and Regulatory Actions

There are no outstanding legal proceedings material to the Corporation to which the Corporation is a party or in respect of which any of its properties are subject, nor are there any such proceedings known to be contemplated.

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

Interest of Management and Others in Material Transactions

None of the current executive officers or directors of Storm, nor any person who is the direct or indirect owner of, or who exercises control over more than 10 percent of any class of securities of Storm, nor any associate or affiliate of such officers or directors or persons has or has had any material interest, direct or indirect, in any transaction or proposed transaction that has materially affected or would materially affect Storm.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Disclosure of Reserves Data

The InSite Report evaluated Storm's natural gas and NGL reserves. Storm has no crude oil reserves. The InSite price forecast dated December 31, 2016 was used to determine all estimates of future net revenue. The tables below are a summary of Storm's natural gas and NGL reserves and the net present value of future net revenue attributed to such reserves as evaluated in the InSite Report based on constant and forecast price and cost assumptions. The tables summarize the data contained in the InSite Report and as a result may contain slightly different numbers than the InSite Report due to rounding. Also due to rounding, certain columns may not add exactly.

The net present value of future net revenue attributable to the Corporation's reserves is stated without provision for interest expense and general and administrative costs, but after providing for estimated royalties, transportation costs, operating costs, development costs, future capital expenditures, and well abandonment costs for only those wells assigned reserves by InSite. The net present value is stated both before and after future income tax. It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to the Corporation's reserves estimated by InSite represents the fair market value of those reserves. Other assumptions and qualifications relating to costs, prices for future production and other matters are summarized herein. The recovery and reserve estimates of Storm's natural gas and NGL reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater than or less than the estimates provided herein.

The InSite Report is based on certain factual data supplied by the Corporation and InSite's opinion of reasonable practice in the industry, including requirements under NI 51-101. The extent and character of ownership and all factual data pertaining to the Corporation's petroleum properties and contracts (except for certain information residing in the public domain or otherwise known to InSite) were supplied by the Corporation to InSite and accepted without any further investigation. InSite accepted this data as presented and neither title searches nor field inspections were conducted.

Reserves Data – Forecast Prices and Costs

Summary of Oil and Gas Reserves

	Gross Reserves			Net Reserves		
	Conventional Natural Gas	Natural Gas Liquids	6:1 Oil Equivalent	Conventional Natural Gas	Natural Gas Liquids	6:1 Oil Equivalent
	(Mmcf)	(Mbbls)	(Mboe)	(Mmcf)	(Mbbls)	(Mboe)
Proved						
Developed Producing	128,363	4,001	25,395	103,237	3,261	20,467
Developed Non-Producing	6,175	194	1,223	4,916	156	976
Undeveloped	255,980	7,815	50,479	208,474	6,474	41,220
Total Proved	390,518	12,011	77,097	316,627	9,891	62,662
Probable	138,591	3,997	27,095	110,429	3,239	21,644
Total Proved plus Probable	529,109	16,007	104,192	427,056	13,131	84,307

Numbers in this table may not add due to rounding.

Capital Program Efficiency with All-In Finding, Development and Acquisition Costs

Based on the evaluation of the Corporation's natural gas and NGL reserves prepared by the independent reserve evaluator, InSite, the efficiency of capital programs is summarized in the table below. Recycle ratio is used to measure performance, reflecting cash flow relative to investment. Recycle ratios are not necessarily calculated in the same manner by all issuers and therefore they should not be used to make comparisons amongst issuers.

	2016	2015	2014
	($/Boe)	($/Boe)	($/Boe)
FD&A Costs – Proved			
Exploration and Development(1)	4.97	5.90	9.68
Acquisitions (net of dispositions)	-	(13.34)	157.62
Total	4.97	3.38	11.68
FD&A Costs – Proved Plus Probable			
Exploration and Development(1)	5.48	6.14	7.99
Acquisitions (net of dispositions)	-	(5.69)	129.91
Total	5.48	0.50	9.64
Field Operating Netback per Boe (including hedging)(2)	8.88	12.89	19.93
Recycle Ratio Based on Field Operating Netback(2)			
Proved	1.8	3.8	1.7
Proved Plus Probable	1.6	25.8	2.1

Notes:

(1) The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserve additions for that year.

(2) Recycle ratio is calculated as field operating netback divided by FD&A costs (proved plus probable including FDC). Field operating netback is a non-IFRS measurement and is calculated as revenue (including realized hedging gains and losses) minus royalties, operating costs and transportation costs.

Net Present Value of Future Net Revenue of Oil and Gas Reserves

	Before Future Income Tax and Discounted at					**Unit Value Using Net Reserves**
	0%	5%	10%	15%	20%	Discounted at 10%/year
	($M)	*($M)*	*($M)*	*($M)*	*($M)*	*($/BOE)*
Proved						
Developed Producing	486,861	383,254	316,836	271,495	238,896	15.48
Developed Non-Producing	21,559	16,257	12,978	10,806	9,285	13.30
Undeveloped	660,527	416,812	270,511	177,437	115,375	6.56
Total Proved	1,168,947	816,323	600,324	459,738	363,556	9.58
Probable	511,202	272,727	157,811	96,661	61,309	7.29
Total Proved plus Probable	1,680,149	1,089,050	758,135	556,398	424,865	8.99

Numbers in this table may not add due to rounding.

	After Future Income Tax and Discounted at				
	0%	5%	10%	15%	20%
	($M)	*($M)*	*($M)*	*($M)*	*($M)*
Proved					
Developed Producing	478,916	379,518	315,007	270,567	238,410
Developed Non-Producing	15,916	13,256	11,326	9,870	8,741
Undeveloped	487,961	303,815	192,667	121,593	73,984
Total Proved	982,794	696,588	519,001	402,030	321,134
Probable	378,529	199,417	112,882	66,808	40,221
Total Proved plus Probable	1,361,323	896,005	631,883	468,838	361,355

Numbers in this table may not add due to rounding.

Additional Information Concerning Future Net Revenue – (Undiscounted)

Reserves Category	**Revenue**	**Royalties**	**Operating Costs**	**Development Costs**	**Abandonment and Reclamation Costs**	**Future Net Revenue Before Income Tax**	**Income Tax**	**Future Net Revenue After Income Tax**
	($M)	($M)	($M)	($M)	($M)	($M)	($M)	($M)
Total Proved	2,586,215	427,934	548,472	412,773	28,089	1,168,947	186,153	982,794
Total Proved plus Probable	3,621,772	612,236	770,738	523,972	34,676	1,680,149	318,826	1,361,323

Future Net Revenue by Product Type (after deduction of royalties, operating costs and future development capital)

		Future Net Revenue Before Income Taxes (Discounted at 10%) ($M)	**Unit Value Using Net Reserves ($)**
Proved	Conventional Natural Gas	600,324	1.60/Mcf
Proved Plus Probable	Conventional Natural Gas	758,135	1.50/Mcf

Future net revenues from conventional natural gas excludes solution gas but includes the value of NGL. Unit values above are after royalties, operating costs and future development capital.

Pricing Assumptions – Forecast Prices and Costs

InSite employed the following pricing, exchange rate and inflation rate assumptions as of December 31, 2016 in estimating the Corporation's reserves data using forecast prices and costs (before deduction of transportation costs).

	Conventional Natural Gas		Light and Medium Crude Oil		Natural Gas Liquids			
Year	Henry Hub	AECO-C Spot	WTI @ Cushing	EDM Ref Price	Butane	Propane	Inflation Rate	CDN/U.S. Exchange Rate
	($U.S./Mmbtu)	($Cdn/Mmbtu)	($U.S./Bbl)	($Cdn/Bbl)	($Cdn/Bbl)	($Cdn/Bbl)	(%/yr)	($U.S./$Cdn)
2017	3.50	3.47	55.00	68.33	47.83	23.92	0%	0.75
2018	3.50	3.42	60.00	72.32	52.07	25.31	2%	0.775
2019	3.75	3.59	65.00	76.05	54.75	26.62	2%	0.80
2020	3.90	3.93	70.00	79.54	57.27	27.84	2%	0.825
2021	4.10	4.01	75.00	82.82	59.63	28.99	2%	0.85
2022	4.25	4.17	80.00	88.60	63.79	31.01	2%	0.85
2023	4.35	4.27	81.60	90.37	65.07	31.63	2%	0.85
2024	4.50	4.43	83.23	92.18	66.37	32.26	2%	0.85
2025	4.59	4.52	84.90	94.02	67.69	32.91	2%	0.85
2026	4.68	4.61	86.59	95.90	69.05	33.57	2%	0.85
2027	4.78	4.70	88.33	97.82	70.43	34.24	2%	0.85
Thereafter +2% per annum								

	2016 Actual Price and Forecast InSite Future Prices Storm Wellhead Gas Price (Cdn$/Mcf)	**2016 Actual Price and Forecast InSite Future Prices Storm Wellhead NGL Price (Cdn$/Bbl)**
2016 Actual(1)	2.01	31.73
2017(2)	3.78	50.20
2018(2)	3.68	57.03
2019(2)	3.89	60.81
2020(2)	4.11	63.97
2021(2)	4.25	66.87

Notes:

(1) 2016 actual wellhead price excludes hedging gains/losses and is after deduction of transportation costs.
(2) InSite forecast prices are after deduction of transportation costs.

Reconciliations of Changes in Reserves

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

	Conventional Natural Gas			Natural Gas Liquids		
Factors	Gross Proved (Mmcf)	Gross Probable (Mmcf)	Gross Proved + Probable (Mmcf)	Gross Proved Mbbl)	Gross Probable (Mbbl)	Gross Proved + Probable (Mbbl)
December 31, 2015	368,482.6	138,588.3	507,070.9	12,020.3	4,190.1	16,210.4
Discoveries	-	-	-	-	-	-
Extensions & Improved Recoveries	26,116.5	(1,507.9)	24,658.6	821.2	(41.4)	779.8
Technical Revisions	19,883.7	1,510.4	21,344.1	13.2	(152.1)	(138.9)
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-
Production	(23,964.9)	-	(23,964.9)	(844.0)	-	(844.0)
December 31, 2016	390,517.9	138,590.8	529,108.7	12,010.7	3,996.6	16,007.3

Numbers in this table may not add due to rounding.

Additional Information Relating to Reserves Data

The following discussion generally describes the basis on which the Corporation attributes proved and probable undeveloped reserves and the Corporation's plans for developing those undeveloped reserves.

Proved and Probable Undeveloped Reserves

Proved undeveloped reserves are generally those reserves that can be estimated with a high degree of certainty and will be recovered from known accumulations where a significant expenditure is required to render them capable of production.

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

Year	Conventional Natural Gas (Mmcf)		Natural Gas Liquids (Mbbls)	
	First Attributed	Cumulative at Year end	First Attributed	Cumulative at Year end
Prior	72.817.6	104,825.7	2,325.3	2,980.3
December 31, 2014	130,476.7	222,301.2	4,068.2	6,560.5
December 31, 2015	74,756.9	258,522.1	2,490.1	8,349.2
December 31, 2016	26,166.5	255,980.2	821.2	7,815.3

Probable undeveloped reserves are those reserves that are less certain to be recovered than proved reserves and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production.

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

Year	Conventional Natural Gas (Mmcf)		Natural Gas Liquids (Mbbls)	
	First Attributed	Cumulative at Year end	First Attributed	Cumulative at Year end
Prior	86,341.3	131,428.7	2,079.7	2,687.6
December 31, 2014	26,556.2	84,453.3	856.1	1,788.4
December 31, 2015	22,695.3	71,924.8	724.5	2,097.1
December 31, 2016	11,619.7	66,873.6	370.6	1,842.8

Proved and probable undeveloped reserves are determined by InSite based on accepted engineering and geological practices as defined under NI 51-101. These practices included the determination of reserves based on the presence of commercial test rates from either production tests or drill stem tests, extensions of known accumulations based upon either geological or geophysical information and the optimization of existing fields. The Corporation is focusing capital investment in 2017 on high NGL content natural gas prospects in the Umbach area of northeast British Columbia.

In general, proved plus probable undeveloped reserves are planned to be developed over the next five years based on available forecast net operating income using the December 31, 2016 InSite future price forecast. It is possible that it could take longer to develop these reserves. There are a number of factors that could result in delayed or cancelled development, including the following: (i) changing economic conditions (due to lower commodity pricing, operating and capital expenditure fluctuations); (ii) changing technical conditions (including production anomalies, such as accelerated depletion); (iii) a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and (iv) surface access issues (including those relating to land owners, weather conditions and regulatory approvals). For more information, see "*Risk Factors*" in this AIF.

Significant Factors or Uncertainties Affecting Reserves Data

The process of estimating reserves is 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 become available and as economic conditions affecting oil and gas prices and costs change. The reserve estimates contained herein are based on current production forecasts, prices and economic conditions. The Corporation's reserves are evaluated by InSite, an independent engineering firm.

As circumstances change and additional data become available, reserve estimates also change. Estimates made 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 governmental restrictions.

Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation is an inferential science. As a result, subjective decisions, technology changes, new geological or production information and a changing operating and regulatory environment will affect these estimates. Revisions to reserve estimates can arise from changes in oil and gas prices, and reservoir performance. Such revisions can be either positive or negative.

Future Development Costs

The table below sets out the development costs deducted in the estimation of future net revenue attributable to proved reserves and proved plus probable reserves (using forecast prices and costs only). At Umbach, there are 67 net future horizontal drilling locations included in the proved category and 81.4 net locations included in the proved plus probable category. In the HRB, there is one net future horizontal drilling location included in the proved category and one net location included in the proved plus probable category.

	Forecast Prices and Costs	
	Proved	Proved Plus Probable
	($M)	($M)
2017	68,700	82,350
2018	125,613	161,058
2019	151,763	170,584
2020	66,697	97,154
2021	-	12,827
2022	-	-
Total Undiscounted	412,773	523,972
Total Discounted at 10% per year	347,044	435,644
Umbach	$400.4 million	$495.1 million
HRB	$ 12.3 million	$ 28.9 million

The Corporation typically relies on two sources of funding to finance its future development costs: (i) internally generated cash flow from operations; and (ii) bank financing when the Corporation's asset base can be used as collateral for bank borrowings. The Corporation considers that these sources are sufficient to fund the future development costs disclosed above using the December 31, 2016 InSite future price forecast.

In 2017, Storm plans to drill 12 gross horizontal wells (12.0 net) and complete 14 horizontal wells (14.0 net) with an estimated 15 gross horizontal wells (15.0 net) starting production during the year, all in the Umbach area of northeast British Columbia.

The Corporation expects to fund its total 2017 capital program with internally generated cash flow and debt. Quarterly fluctuations in sources of funding are expected.

Interest or other costs of external funding are not included in the reserves and future net revenue estimates set forth above and would reduce the reserves and future net revenue to some degree depending upon the funding sources utilized. Storm does not anticipate that interest or other funding costs would make development of any of the oil and gas assets uneconomic.

Oil and Gas Properties

Summarized information about Storm's operations and principal operating areas, properties and operations is as follows:

Umbach, Northeast British Columbia

Storm's land holdings as at December 31, 2016 in the Montney formation total 109,000 net acres, or 155 net sections. Production in 2016 averaged 13,080 Boe per day (17% NGL). All of Storm's $65.5 million gross capital investment in 2016 was invested in Umbach. Two project areas have been identified with Umbach North consisting of 20 net sections of jointly owned lands with an average Storm working interest of approximately 60%, and Umbach South, including Nig, consisting of 135 net sections of land at a 100% working interest as at December 31, 2016.

In 2016, 12 Montney horizontal wells (12.0 net) were drilled, 10 horizontal wells (10.0 net) were completed and nine horizontal wells (9.0 net) began producing. In 2017, Storm plans to drill 12 horizontal wells (12.0 net), complete 14 horizontal wells (14.0 net), and anticipates that a total of 15 horizontal wells (15.0 net) will commence production during the year.

In 2016, Storm constructed a third field compression facility with initial capacity of 35 Mmcf per gas, which is expandable to 70 Mmcf per day. Start-up of this facility occurred on January 12, 2017. Storm now operates three 100% working interest field compression facilities that have total capacity of 115 Mmcf per day. Upon expansion of the third field compression facility, Storm's capacity would increase to 150 Mmcf per day which supports growth in corporate production to approximately 27,000 Boe per day. Depending on natural gas pricing and funds flow, preliminary planning would see this achieved in the second half of 2018.

Grande Prairie Area, Northwest Alberta

Production in 2016 averaged approximately 26 Boe per day. Following the 2015 Grande Prairie Disposition, there remains one property in the Grande Prairie area capable of producing 300 Boe per day which was shut in during August 2015. Partial production has recently been restored, however, capital invested on this property by the Corporation in 2016 was insignificant and minimal activity is planned for 2017.

Horn River Basin, Northeast British Columbia

Storm, through a predecessor company, began acquiring undeveloped land in the HRB in 2008 in partnership with SGR (40% Storm, 60% SGR). As at December 31, 2016, Storm has a 100% working interest in 119 sections in the HRB (78,000 net acres) which is prospective for natural gas from the Muskwa, Otter Park and Evie/Klua shales. Storm's one horizontal well averaged 310 Boe per day in the fourth quarter of 2016. Cumulative production to date from this well is 5.3 Bcf raw. A core area totaling 30 sections (100% working interest) has been proven to be productive with this producing horizontal well plus two vertical wells that were completed with final test rates of 900 Mcf per day over the final 24 hours of each flow test. Lands within the 30 section area have been continued through drilling and are not subject to expiry. The remaining 89 sections may be subject to expiry over a period of several years beginning in 2020.

Storm has no plans for additional activity in the area until there is evidence of a substantial and sustainable increase in natural gas prices.

Oil and Gas Wells

The following table summarizes the Corporation's interest as at December 31, 2016 in wells that are producing and non-producing. All of the wells in which Storm has an interest are located onshore in the Provinces of Alberta and British Columbia.

	Producing Wells				**Non-Producing Wells**			
	Oil		Natural Gas		Oil		Natural Gas	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
British Columbia	-	-	47.0	44.2	-	-	44.0	39.6
Alberta	-	-	4.0	4.0	5.0	3.3	9.0	6.7
Total	-	-	51.0	48.2	5.0	3.3	53.0	46.3

Properties With No Attributed Reserves

The following table summarizes the gross and net acres of unproved properties in which the Corporation has an interest at December 31, 2016 and also the number of net acres for which the Corporation's rights to explore, develop or exploit will, absent further action, expire within one year of December 31, 2016.

	Gross Acres	**Net Acres**	**Net Acres Expiring Within One Year**
Umbach Montney - BC	121,178	109,378	-
Horn River Basin - BC	81,115	78,264	-
Grande Prairie - AB	12,640	7,491	-
Other areas	62,360	44,122	-
Total	277,292	239,255	-

Notes:

(1) "**Gross**" in this chart means the total number of acres in which the Corporation holds an interest.
(2) "**Net**" in this chart means the aggregate of the percentage working interests of Storm in the gross acres.

The pace of development of these unproved properties is subject to capital allocation constraints and is influenced by many factors, including the results of exploration and development activities of Storm and others in the area, infrastructure capacity constraints and Storm's short-term and long-term view of oil and natural gas prices. Storm currently has no material work commitments on lands with no attributed reserves.

Forward Contracts

Storm is exposed to market risks resulting from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of operations. A variety of derivative instruments may be used by Storm to reduce its exposure to fluctuations in commodity prices and foreign exchange rates.

Commodity price hedges are used to support longer term growth by providing some stability regarding future revenue and funds flow. The objective is to hedge 50% of most recent quarterly or monthly production for the next 12 months and 25% for the following 13 to 24 months. Anticipated production growth is not hedged.

Details of commodity price contracts in respect of Storm's hedging activities can be found in Note 14, "Financial Instruments", to Storm's audited consolidated financial statements for the year ended December 31, 2016 which have been filed on SEDAR (www.sedar.com). See "*Risk Factors*" for additional information on the risks and uncertainties relating to Storm's hedging activities.

Tax Horizon

As at December 31, 2016, the Corporation had resource pools and operating losses of approximately $462 million available for deduction against future taxable income. These existing pools, plus pool additions through the Corporation's capital program in 2017 and beyond, mean that the Corporation does not expect to pay income tax for a considerable number of years unless commodity prices show material improvement from what was realized in 2016. However, measurement of losses and tax pools and their availability can be subject to audit and reassessment by Canada Revenue Agency, potentially several years later.

Costs Incurred

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

Capital Investment ($M)

	Property Acquisition Costs			
	Proved Properties	Unproved Properties	Exploration Costs	Development Costs
Costs ($M)	-	1,413	-	64,125

Exploration and Development Activities

The following table summarizes the gross and net exploration and development wells in which the Corporation participated during the year ended December 31, 2016.

	Development Wells		**Exploration Wells**		**Total Wells**	
	Gross	Net	Gross	Net	Gross	Net
Natural gas wells	12.0	12.0	-	-	12.0	12.0
Oil wells	-	-	-	-	-	-
Service wells	-	-	-	-	-	-
Stratigraphic test wells	-	-	-	-	-	-
Dry holes	-	-	-	-	-	-
Total	12.0	12.0	-	-	12.0	12.0

During 2017, the Corporation will focus on further development in the Umbach area of northeast British Columbia. Subject to the availability of capital, Storm intends to drill a total of 12 gross horizontal wells (12.0 net), complete 14 horizontal wells (14.0 net), and anticipates a total of 15 gross wells (15.0 net) starting production during the year, all in the Umbach area.

Production Estimates

Gross – Production by Product

The following tables disclose for each product type the total volume of production estimated by InSite for 2017 based on the Corporation's reserves and ownership at December 31, 2016.

2017	**Conventional Natural Gas** (Mmcf)	**Natural Gas Liquids** (Mbbls)	**Boe/d**
Proved			
Umbach	31,527.7	1,066.0	17,317
HRB	624.4	-	285
Grande Prairie	328.7	3.2	159
Total Proved	32,480.9	1,069.2	17,761
Proved Plus Probable			
Umbach	32,012.5	1,087.1	17,596
HRB	636.8	-	291
Grande Prairie	333.1	3.2	161
Total Proved Plus Probable	32,982.4	1,090.3	18,048

Production History

The following tables summarize certain information in respect of production, product prices received, royalties paid, operating expenses and resulting netback for the periods indicated below. Note that for the purposes of the two tables below, "Condensate" is field condensate and pentane recovered at gas plants, and "NGL" is propane and butane recovered at gas plants.

	2016 Quarter Ended			
	Q4 Dec. 31	**Q3** Sept. 30	**Q2** June 30	**Q1** March 31
Average Daily Production[1]				
Conventional Natural Gas (Mcf/d)	66,173	65,914	63,800	66,012
Condensate (Bbls/d)	1,381	1,210	1,047	964
NGL (Bbls/d)	910	1,089	1,172	1,452
Combined (Boe/d)	13,320	13,285	12,852	13,418
Average Price Received[1][3]				
Conventional Natural Gas ($/Mcf)	2.86	2.41	1.28	1.62
Condensate ($/Bbl)	57.17	49.01	50.05	41.54
NGL ($/Bbl)	18.64	10.03	11.63	10.44
Combined ($/Bbl)	21.42	17.22	11.86	13.20
Royalties Paid				
Conventional Natural Gas ($/Mcf)	(0.05)	(0.13)	0.05	(0.05)
Condensate ($/Bbl)	(5.82)	(5.16)	(4.43)	(3.57)
NGL ($/Bbl)	(2.03)	(1.02)	(0.63)	(1.41)
Combined ($/Boe)	(0.99)	(1.19)	(0.19)	(0.76)
Operating & Transportation Expenses				
Conventional Natural Gas ($/Mcf)	(1.45)	(1.38)	(1.39)	(1.40)
Condensate ($/Bbl)	(3.09)	(2.79)	(2.14)	(3.14)
NGL ($/Bbl)	-	-	-	-
Combined ($/Boe)	(7.50)	(7.08)	(7.09)	(7.24)
Netback Received[2][3]				
Conventional Natural Gas ($/Mcf)	1.37	0.90	(0.06)	0.16
Condensate ($/Bbl)	48.26	41.06	43.48	34.82
NGL ($/Bbl)	16.62	9.01	11.00	9.02
Combined ($/Boe)	12.93	8.95	4.58	5.20

Notes:

(1) Before deduction of royalties.
(2) Netbacks are non-IFRS measurements and are calculated by subtracting royalties and operating and transportation costs from revenues.
(3) Before hedging activities.

The following table sets out the production volumes for each of Umbach, HRB and Grande Prairie for the year ended December 31, 2016:

	Conventional Natural Gas (Mmcf)	**Condensate** (Mbbls)	**Natural Gas Liquids** (Mbbls)
Umbach	64,644	1,303	1,003
HRB	680	-	-
Grande Prairie	154	-	-
Total	65,478	1,303	1,003

DIVIDENDS AND DISTRIBUTIONS

The Corporation has not declared or paid any dividends on its Common Shares since incorporation on June 8, 2010. Any decision to pay dividends on the Common Shares will be made by the Board of Directors on the basis of the Corporation's earnings, financial requirements and other conditions existing at such future time.

DESCRIPTION OF SHARE CAPITAL

The authorized capital of Storm consists of an unlimited number of Common Shares and an unlimited number of first preferred shares (the "**First Preferred Shares**"), issuable in series. As at March 31, 2017, an aggregate of 121,556,812 Common Shares were issued and outstanding and no First Preferred Shares were issued or outstanding.

The following is a summary of the rights, privileges, restrictions and conditions that attach to the Common Shares and the First Preferred Shares.

Common Shares

Storm is authorized to issue an unlimited number of Common Shares. Holders of Common Shares are entitled to one vote per share at meetings of holders of Common Shares, to receive dividends if, as and when declared by the Board of Directors and to receive pro rata the remaining property and assets of Storm upon its dissolution or winding up, subject to the rights of shares having priority over the Common Shares.

First Preferred Shares

Storm is authorized to issue an unlimited number of First Preferred Shares without nominal or par value. First Preferred Shares have priority over Common Shares in the event of liquidation, dissolution or winding up of the Corporation.

MARKET FOR SECURITIES

The Common Shares are listed and posted for trading on the TSXV under the symbol "SRX". The following table sets forth the price range and trading volume of these securities as reported by the TSXV for the period January 1, 2016 to December 31, 2016.

Month	High ($)	Low ($)	Volume
January 2016	3.97	2.91	2,130,199
February 2016	3.92	3.05	2,781,069
March 2016	3.55	3.11	8,316,009
April 2016	4.28	3.22	2,728,004
May 2016	4.25	3.50	3,126,465
June 2016	4.45	3.24	1,153,715
July 2016	4.45	3.71	4,792,701
August 2016	4.44	3.92	2,775,683
September 2016	5.20	4.30	2,852,735
October 2016	5.30	4.72	5,362,543
November 2016	5.65	4.44	3,543,233
December 2016	5.66	5.00	4,018,694

PRIOR SALES

The following table summarizes the issuances of securities convertible into Common Shares during the year ended December 31, 2016:

Date of Issuance	Description of Transaction	Number and Type of Securities	Price per Security
November 1, 2016	Grant of Options	192,000 Options	$4.90
December 1, 2016	Grant of Options	180,000 Options	$5.50
December 13, 2016	Grant of Options	1,659,000 Options	$5.43

INDUSTRY CONDITIONS

The oil and natural gas industry is subject to extensive controls and regulation governing its operations (including land tenure, exploration, development, production, refining, transportation and marketing) imposed by legislation enacted by various levels of government and with respect to pricing and taxation of oil and natural gas by agreements among the governments of Canada, Alberta, and British Columbia, all of which should be carefully considered by investors. Within the knowledge of management, 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 principal aspects of legislation, regulations and agreements governing the oil and gas industry.

Pricing and Marketing - Oil and Natural Gas

The price of natural gas 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 with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas (other than propane, butane and ethane) exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 m^3/day) must be made pursuant to an NEB order. 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.

On July 6, 2012, the federal government enacted the *Jobs, Growth and Long-term Prosperity Act* which made amendments to the *National Energy Board Act* that affect the NEB's export and import framework. As a result of these changes, the NEB issued the Interim Memorandum of Guidance Concerning Oil and Gas Export Applications and Gas Import Applications under Part VI of the *National Energy Board Act* ("**Interim Oil and Gas MOG**"). The purpose of the Interim Oil and Gas MOG is to provide guidance to applicants until such time as the NEB has completed the review and update of the regulatory framework. As part of the review and update, the NEB is currently proposing amendments to the *National Energy Board Part VI (Oil and Gas) Regulations* and the *National Energy Board Export and Import Reporting Regulations.*

Producers of oil are entitled to negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Such price depends in part on oil quality, prices of competing oils, distance to market, the value of refined products and the supply/demand balance. Oil exporters are also entitled to enter into export contracts with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude oil, provided that an order approving such export has been obtained from the NEB. Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an export licence from the NEB and the issuance of such licence requires the approval of the Governor in Council and a public hearing.

The government of Alberta also regulates the volume of natural gas which may be removed from the province for consumption elsewhere based on such factors as reserve availability, transportation arrangements and market considerations.

The lack of pipeline capacity has recently limited the ability of some companies to produce and market portions of their natural gas production although pipeline expansions are ongoing. In addition, the prorating of capacity on the interprovincial pipeline systems continues to limit oil exports.

Furthermore, recent years have seen the emergence of new sources of supply as natural gas deposits formerly regarded as inaccessible, particularly those locked in shales and other tight formations, both in Canada and the U.S., are now being exploited through new drilling and fracturing applications. From 2009 onwards, increased supply of natural gas from these sources, coupled with other factors such as reduced residential and industrial demand, resulted in a decrease in the price for natural gas. The effect on natural gas supply, as production of shale and other tight gas matures, cannot be determined, but the contribution of shale gas to aggregate supply will likely have a continuing and considerable influence on natural gas pricing, at least in the short and medium term.

From 2009 through to 2017, Pacific Rim countries, particularly China, Japan and South Korea, through sovereign oil companies, or representatives of end users, have expressed interest in or invested in, infrastructure projects and exploration and development activities in Canada, with a view to securing sources of future supply. Infrastructure projects have a long lead time, but if consummated, may result in Canada becoming a significant exporter of liquefied natural gas to the Pacific Rim, as an additional or successor market to the U.S. It may also lead to future internationalization of pricing for natural gas.

According to the NEB, in 2016 the North American natural gas market continues to be oversupplied. Storage inventories in the U.S. began 2016 above historical averages due to a warmer than usual winter. Strong U.S. gas production, ample inventories and reduced heating demand are expected to keep the market amply supplied and could keep price soft for most of 2017.

The North American Free Trade Agreement

The North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, the United States and Mexico became effective on January 1, 1994. NAFTA carries forward most of the material energy terms that are contained in the Canada - U.S. Free Trade Agreement. Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to 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 or maximum 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. The agreement 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 natural gas exports.

The government of the United States has publicly announced its interest in renegotiating NAFTA. It is uncertain whether the government of the United States will successfully change or alter the terms of NAFTA.

Trans-Pacific Partnership

On October 5, 2015, Canada and 11 other countries announced an agreement in respect of the Trans-Pacific Partnership ("**TPP**"). Canada and each participating country must ratify the TPP in their national legislatures. The TPP is the most ambitious trade initiative in the Asia-Pacific region. The TPP would lower tariffs on a wide range of Canadian products and benefit exporters across Canada in a number of sectors, including agriculture, wood and wood products, chemicals and plastics, and fish and seafood. An agreement would also bring enhanced and more predictable market access for Canada's service industries. On January 25, 2017, the Government of Canada confirmed that it would sign the TPP though it has yet to be ratified by the House of Commons.

On January 23, 2017, United States President Trump signed a Presidential Memorandum directing the United States Trade Representative to withdraw the United States as a signatory to the TPP and to permanently withdraw the United States from TPP negotiations. It is uncertain whether the remaining signatories to the TPP will ratify the TPP or will seek to change or alter the terms of the TPP.

Extractive Sector Transparency Measures Act

The Extractive Sector Transparency Measures Act ("**ESTMA**"), a federal regime for the mandatory reporting of payments to government, came into force on June 1, 2015. ESTMA contains broad reporting obligations with respect to payments to governments and state owned entities, including employees and public office holders, made by Canadian businesses involved in resource extraction. Under ESTMA, all payments made to payees (broadly defined to include any government or state owned enterprise) must be reported annually if the aggregate of all payments in a particular category to a particular payee exceeds $100,000 per financial year. The categories of payments include taxes, royalties, fees, bonuses, dividends and infrastructure improvement payments. Payments to aboriginal governments are exempt from reporting obligations until June 1, 2017. Failure to comply with the reporting obligations under ESTMA is punishable upon summary conviction with a fine of up to $250,000. In addition, each day that passes prior to a non-compliant report being corrected forms a new offence, and therefore, a payment that goes unreported for a year could result in over $9,000,000 in total liability.

Provincial Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations which govern land tenure, royalties, production rates, environmental protection and other matters. The royalty regime is a significant factor in the profitability of crude oil, NGL, sulphur and natural gas production. Royalties payable on production from minerals other than Crown-owned minerals are determined by negotiations between the mineral owner and the lessee although production from such lands is subject to certain provincial taxes and royalties. 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 well productivity, geographical location, field discovery date and the type or quality of the petroleum product produced.

From time to time, the provincial governments of the western Canadian provinces create incentive programs for exploration and development. Such programs often provide for royalty reductions, royalty holidays and credits, and are generally introduced when commodity prices are low. The programs are designed to encourage exploration and development activity by improving near-term earnings and cash flow within the industry.

British Columbia

Producers of oil and natural gas in the Province of British Columbia are required to pay annual rental payments with respect to the Crown leases and royalties plus freehold production taxes in respect of oil and gas produced from Crown and freehold lands. The amount payable as a royalty in respect of oil depends on the type of oil, the value of the oil, the quantity of oil produced in a month, and the vintage of the oil. Generally, the vintage of oil is based on the determination of whether the oil is produced from a pool discovered before October 31, 1975 (old oil), between October 31, 1975, and June 1, 1998 (new oil), or after June 1, 1998 (third tier oil). The royalty rates are calculated in three stages, which take into account the vintage of the oil, if the oil produced has already been sold and any royalty exempt value applicable (exempt wells). Oil produced from newly discovered pools may be exempt from the payment of a royalty for the first 36 months of production if it is not more than either: (i) the monthly allowable production multiplied by 36; or (ii) 11,450 m^3 produced. The royalties for third tier oil are the lowest, reflecting the higher costs of exploration and extraction that the producers would incur.

The royalty payable on natural gas is determined by a sliding scale based on a reference price, which is the greater of the price obtained by the producer, and a prescribed minimum price. However, when the reference price is below the select price (a parameter used in the royalty rate formula), the royalty rate is fixed. As an incentive for the production and marketing of natural gas which may otherwise have been flared, natural gas conserved and produced in association with oil has a lower royalty than the royalty payable on non-conservation gas.

British Columbia has put in place a number of targeted royalty programs for key resource areas intended to increase the competitiveness of British Columbia's low productivity wells. These include both royalty credit and royalty reduction programs, including the following:

- Deep Well Royalty Credit Program applies to vertical and horizontal natural gas wells but not to gas wells that are part of a coalbed methane project. The credit available for a well is dependent on the vertical depth of the completion interval for vertical wells and the vertical depth plus the horizontal length for horizontal wells. Tier 1 targets shallower horizontal wells with a spud date after April 1, 2014 where the vertical depth of the horizontal lateral is shallower than 1,900 metres and the credit ranges from a minimum of $0.44 million to a maximum of $2.81 million. The minimum royalty rate for horizontal wells under Tier 1 is 6%. Tier 2 targets vertical wells with a completed interval deeper than 2,500 metres and horizontal wells with a vertical depth greater than 1,900 metres with the size of the credit varying with the location of the well (whether it is "east" or "west") and the concentration of hydrogen sulfide in the gas produced from the well (whether the well is "sweet" or "sour"). The minimum royalty rate for wells under Tier 2 is 3%;

- Deep Re-Entry Royalty Credit Program providing royalty credits for deep re-entry wells with a true vertical depth greater than 2,300 metres which increases with the incremental distance drilled. A well can qualify for both the deep well and deep re-entry credits;

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

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

- Marginal Royalty Reduction Program providing a royalty reduction for low productivity natural gas wells which have a spud date after May 31, 1998, average monthly production under 25,000 m^3 per day, and average daily production over the first 12 calendar months of less than 23 m^3 for every metre of well depth; and

- Ultra Marginal Royalty Program is intended to increase the development of shallow natural gas wells (up to 2,500 metres) with low rates of production. The qualification criteria were updated in March 2014 and horizontal wells that spud on or after April 1, 2014 are not eligible for this program. Wells with a spud date on or before March 31, 2014 qualify if the vertical well has a completed depth of less than 2,500 metres or if a horizontal well has a vertical depth of less than 2,300 metres. If the average daily production during a month is less than 60,000 m3 (2,127 Mcf), the royalty rate for the well is reduced depending on the vertical depth and the well classification ("exploratory wildcat" or "exploratory outpost" or "development").

Oil produced from an oil well event on either Crown or freehold land and completed in a new pool discovery subsequent to June 30, 1974 may also be exempt from the payment of a royalty for the first 36 months of production or 11,450 m3 of production, whichever comes first.

The Government of British Columbia also maintains an Infrastructure Royalty Credit Program (the "**Infrastructure Royalty Credit Program**") which provides royalty credits for up to 50% of the cost of certain approved road construction or pipeline infrastructure projects intended to improve, or make possible access to new and underdeveloped oil and gas areas. In February 2016, the Government of British Columbia expanded the Infrastructure Royalty Credit Program for three years offering $120 million in royalty credits. Any changes to the royalty regime in British Columbia may have a material effect on the Corporation. See "*Risk Factors – Royalties*".

Alberta

On March 3, 2009, the Government of Alberta announced a three-point incentive program to stimulate new and continued economic activity in Alberta which included a drilling royalty credit for new conventional oil and natural gas wells and a new well royalty incentive program. Under the drilling royalty credit program, a $200 per metre royalty credit was available on new conventional oil and natural gas wells drilled between April 1, 2009 and March 31, 2011, subject to certain maximum amounts. The maximum credits available were determined by a company's production level in 2008 and its drilling activity between April 1, 2009 and March 31, 2011. The new well incentive program applies to certain wells beginning production of conventional oil and natural gas after April 1, 2009 and provides for a maximum 5% royalty rate for the first 12 months of production, up to a maximum volume including all products of 7,949 cubic metres equivalent for oil wells and 14,100 cubic metres equivalent for gas wells.

On May 27, 2010, the Government of Alberta announced changes to the existing royalty framework under the *Petroleum Royalty Regulation, 2009* and the *Natural Gas Royalty Regulation, 2009* which became effective January 1, 2011 (the "**Alberta Royalty Framework**"). Changes included making the Natural Gas Deep Drilling Program, which adjusts the royalties for deep gas wells, a permanent initiative under the Alberta Royalty Framework. Qualifying wells under the Natural Gas Deep Drilling Program include natural gas wells with gas-oil ratios of greater than 1,800:1 which have been spud or deepened on or after May 1, 2010 and have a true vertical depth greater than 2,000 metres. An Emerging Resources and Technologies Initiative was also created to encourage new exploration and development from higher cost and more technically challenging resources, such as shale gas, coal seams and horizontal oil and gas wells. In particular, pursuant to the Emerging Resource and Technologies Initiative: (a) coalbed methane wells will receive a maximum royalty rate of 5 percent for 36 producing months on up to 750 MMcf of production, retroactive to wells that began producing on or after May 1, 2010; (b) shale gas wells will receive a maximum royalty rate of 5 percent for 36 producing months with no limitation on production volume, retroactive to wells that began producing on or after May 1, 2010; (c) horizontal gas wells will receive a maximum royalty rate of 5 percent for 18 producing months on up to 500 MMcf of production, retroactive to wells that commenced drilling on or after May 1, 2010; and (d) horizontal oil wells and horizontal non-project oil sands wells will receive a maximum royalty rate of 5 percent with volume and production month limits set according to the depth (including the horizontal distance) of the well, retroactive to wells that commenced drilling on or after May 1, 2010.

On January 29, 2016, the Alberta government announced changes to the Alberta Royalty Framework. Under the new modern royalty framework (the "**MRF**"), the sliding scale royalty concept will be maintained, but will be achieved with a greater degree of simplicity. The new royalty percentage will be applied to the gross revenue generated from all hydrocarbons, with no differentiation between produced substances, and wells will be charged a flat 5% royalty rate until revenues exceed a normalized well cost allowance, which will be based on vertical well depth and lateral length. The calculation of this cost allowance, and other details regarding the various parameters within the new formula under the MRF was announced in 2016 and was fully implemented as of January 1, 2017. Prior to January 1, 2017, the former royalty framework continued to apply to any wells drilled prior to that date, and thereafter for a period of 10 years following which, such wells will be transitioned into the MRF.

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

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.

Each of the provinces of Alberta and British Columbia has implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a lease or license.

Alberta also has a policy of “shallow rights reversion”, introduced under the royalty regime introduced in October of 2007, which provides for the revision to the Crown which provides, for the reversion to the Crown of mineral rights to shallow, non-productive geological formations for all leases and licenses. For leases and licenses issued subsequent to January 1, 2009, shallow rights reversion will be applied at the conclusion of the primary term of the lease or license. Holders of leases or licences that have been continued indefinitely prior to January 1, 2009 will receive a notice regarding the reversion of the shallow rights, which will be implemented three years from the date of the notice. The order in which these agreements will receive the reversion notice will depend on their vintage and location, with the older leases and licenses receiving reversion notices first. Leases and licences that were granted prior to January 1, 2009 but continued after that date will not be subject to shallow rights reversion until they reach the end of their primary term and are continued (at which time deep rights reversion will be applied); thereafter, the holders of such agreements will be served with shallow rights reversion notices based on vintage and location similar to leases and licences that were already continued as of January 1, 2009. In 2013, Alberta Energy placed an indefinite hold on serving shallow rights reversion notices for leases and licences that were granted prior to January 1, 2009. Alberta Energy stated that it will provide the industry with notice if, in the future, a decision is made to serve additional shallow rights reversion notices.

Environmental Protection Requirements

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to evolving national, provincial and municipal laws and regulations, as well as, potentially, international conventions. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases, discharges, or emissions of various substances produced in association with oil and gas operations, habitat protection and minimum setbacks of oil and gas activities from fresh water bodies. 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 may result in the imposition of fines, penalties and sanctions, some of which may be material or materially affect the Corporation’s operations. 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. Further, as Canadian environmental legislation evolves, the use of administrative penalties by the imposition of fines for the commission of environmental offences on an absolute liability basis has grown.

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

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 the Corporation to incur costs to remedy such discharge in the event that they are not covered by the Corporation's insurance. Although the Corporation 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. Environmental legislation in the Province of Alberta is, for the most part, set out in the *Environmental Protection and Enhancement Act* ("**EPEA**"), the *Water Act* and the *Oil and Gas Conservation Act* ("**OGCA**"). The EPEA and the OGCA impose strict environmental standards with respect to releases of effluents and emissions, require stringent compliance, reporting and monitoring obligations, and impose significant penalties for non-compliance.

The regulatory landscape in Alberta has undergone a transformation from multiple regulatory bodies to a single regulator for upstream oil and gas, oil sands and coal development activity. On June 17, 2013, the Alberta Energy Regulator (the "**AER**") assumed the functions and responsibilities of the former Energy Resources Conservation Board, including those found under the OGCA. On November 30, 2013, the AER assumed the energy related functions and responsibilities of Alberta Environment and Parks ("**AEP**") in respect of the disposition and management of public lands under the *Public Lands Act.* On March 29, 2014, the AER assumed the energy related functions and responsibilities of AEP in the areas of environment and water under EPEA and the *Water Act,* respectively. The AER's responsibilities exclude the functions of the Alberta Utilities Commission and the Surface Rights Board, as well as Alberta Energy's responsibility for mineral tenure. The objective behind the transformation to a single regulator is the creation of an enhanced regulatory regime that is efficient, attractive to business and investors, and effective in supporting public safety, environmental management and resource conservation while respecting the rights of landowners.

In British Columbia, energy projects may be subject to review pursuant to the provisions of the *Environmental Assessment Act* (British Columbia), which rolls the previous processes for the review of major energy projects into a single environmental assessment process that contemplates public participation in the environmental review. Other environmental protection and management measures, including reclamation, are governed by the *Oil and Gas Activities Act* (British Columbia) and the *Environmental Management Act* (British Columbia).

The oil and gas industry is subject to such environmental regulations which include restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and gas industry operations. In addition, such legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage and the imposition of material fines and penalties.

As of December 31, 2016, the Corporation owned approximately 109 gross and 97.8 net wells for which abandonment and reclamation costs are expected to be incurred. As disclosed in the Corporation's audited consolidated financial statements for the year ended December 31, 2016, the total undiscounted amount required to settle the Corporation's future asset retirement obligations, including environmental remediation, is estimated to be $28.3 million. The Corporation estimates abandonment and reclamation costs by taking account of the costs associated with decommissioning, abandonment, remediation and reclamation, all adjusted according to the Corporation's working interest and appropriately discounted. Such costs are individually attributed to assets then aggregated to determine the total liability and are not reduced by salvage values.

The Corporation believes it is in material compliance with environmental legislation in the jurisdictions in which it operates at this time. The Corporation's practice is to do all that it reasonably can to ensure that it remains in material compliance with environmental protection legislation. The Corporation also believes that it is reasonably likely that the trend towards stricter standards in environmental legislation and regulation will continue. The Corporation 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 that environmental laws will not result in a curtailment of production, a material increase in the costs of production or the costs of development or exploration activities, or otherwise adversely affect the Corporation's financial condition, capital expenditures, results of operations, competitive position or prospects.

Liability Management Rating Programs

British Columbia

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

In British Columbia, the British Columbia Oil and Gas Commission administers a Liability Management Rating Program (the "**LMR Program**"), the purpose of which is to ensure that permit holders for upstream oil and gas wells, facilities and pipelines are responsible for the financial risks related to their operations. Updated as of June 2016, the LMR Program aids in determining the security deposits required by permit holders to protect against those who may not be capable of meeting abandonment and reclamation obligations. The LMR Program is used to identify permit holders whose liabilities exceed assets (permit holders with a calculated ratio of deemed assets to deemed liabilities of less than 1.0), and it requires that said permit holders take action to mitigate any financial risks represented by the difference in the calculation. The ratio of deemed liabilities to deemed assets is assessed once each month and failure to post the required security deposit may result in the initiation of enforcement action by the British Columbia Oil and Gas Commission.

Alberta

In Alberta, the AER similarly administers the Licensee Liability Rating Program (the "**LLR Program**") as part of the Liability Management Rating Assessment Process. The LLR Program is a liability management program governing most conventional upstream oil and gas wells, facilities and pipelines. The OGCA establishes an orphan fund (the "**Orphan Fund**") to pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline included in the LLR Program if a licensee or working interest participant ("**WIP**") becomes defunct. The Orphan Fund is funded by licensees in the LLR Program through a levy administered by the AER. The LLR Program is designed to minimize the risk to the Orphan Fund posed by unfunded liability of licensees and prevent the taxpayers of Alberta from incurring costs to suspend, abandon, remediate and reclaim wells, facilities or pipelines. The LLR Program requires a licensee whose deemed liabilities exceed its deemed assets to provide the AER with a security deposit. The ratio of deemed liabilities to deemed assets is assessed once each month and upon the submission of a license transfer application, and failure to post the required security deposit may result in the initiation of enforcement actions by the AER.

On May 1, 2013, the AER began to implement a three year program of changes to the LLR Program. Some of the important changes which were implemented through this three year process include: (a) increases to the prescribed average reclamation cost for each individual well or facility (which increased a licensee's deemed liabilities); (b) increases to facility abandonment cost parameters for each well equivalent (which increased a licensee's deemed liabilities); (c) use of an industry netback averaged over the last three years (which affected the calculation of a licensee's deemed assets); and (d) a change to the present value and salvage factor, which increases to 1.0 for all active facilities from 0.75 for active wells and 0.50 for active facilities (which increased a licensee's deemed liabilities).

The changes were implemented over the period ending August 2015. The first phase was implemented in May 2013, the second phase was implemented in May 2014 and the final phase was implemented in August 2015. The changes to the LLR Program stem from concern that the previous regime significantly underestimated the environmental liabilities of licensees.

Further, on July 4, 2014, the AER introduced the inactive well compliance program (the "**IWCP**") to address the growing inventory of inactive wells in Alberta and to increase the AER's surveillance and compliance efforts under *Directive 013: Suspension Requirements for Wells* ("**Directive 013**"). The IWCP applies to all inactive wells that are noncompliant with Directive 013 as of April 1, 2015. The objective is to bring all inactive noncompliant wells under the IWCP into compliance with the requirements of Directive 013 within five years. As of April 1, 2015, each licensee will be required to bring 20% of its inactive wells into compliance every year, either by reactivating or suspending the wells in accordance with Directive 013 or by abandoning them in accordance with *Directive 020: Well Abandonment*.

In June 2016, the AER released Bulletins 2016-16 and 2016-21 which, among other things, implement important changes to the AER's LLR Program, licence eligibility and transfers. Bulletin 2016-16 introduced changes requiring, as a condition to transferring existing AER licenses, approvals and permits, the AER would require all transferees to demonstrate a liability management ratio ("**LMR**") of 2.0 or higher immediately following the transfer. The LMR is the ratio of a permit holder's deemed assets to deemed liabilities. Bulletin 2016-21 clarified that transferees must either demonstrate an LMR of 2.0 or higher or provide other evidence that the transferee will be able to meet their obligations with an LMR of less than 2.0. These changes may impact the Corporation's ability to transfer licenses, approvals or permits, and may result in increased costs and delays.

International and Domestic Regulations

Federal

In common with all producers, the Corporation's exploration activities and production facilities emit carbon dioxide, methane, nitrous oxide and other so-called "greenhouse gases" ("**GHG**").

Canada is a signatory to the United Nations Framework Convention on Climate Change ("**UNFCCC**"), which was entered into in order to work towards stabilizing atmospheric concentrations of greenhouse gas ("**GHG**") emissions at a level to prevent "dangerous anthropogenic interference with the climate system". The UNFCCC came into force on March 21, 1994. Subsequent international negotiations led to the Kyoto Protocol, an international treaty which extends the UNFCCC and commits its signatories to reduce GHG emissions. The Kyoto Protocol was adopted in December 1997 and came into force on

February 16, 2005. Canada withdrew from the Kyoto Protocol effective December 2012. On December 12, 2015, the UNFCCC adopted the Paris Agreement, which Canada ratified on October 5, 2016.

In May 2015, Canada submitted its Intended Nationally Determined Contribution ("**INDC**") to the UNFCCC Secretariat, pledging a 30% reduction from 2005 levels – approximately 523 megatonnes – by 2030. In addition, provincial/territorial and federal leaders met and agreed that they would work together to build a national climate change plan. At a follow-up meeting of the First Ministers and Prime Minister on March 3, 2016, the parties agreed under the Vancouver Declaration on Clean Growth and Climate Change to launch a process to develop the Pan-Canadian Framework on Clean Growth and Climate Change (the "**Framework**"), which was released on December 9, 2016 at the First Ministers meeting. Saskatchewan was the only province that decided not to adopt the Framework. Prior to the release of the Framework, the federal government announced in October 2016 that it will set a minimum price on carbon starting at $10 per tonne of CO2e in 2018, which will increase by $10 per year until it reaches $50 per tonne of CO2e by 2022. This approach will be reviewed in 2022 to confirm the path forward, including continued increases in stringency. Under the federal plan, each province and territory will be required to implement carbon pricing in its jurisdiction by 2018, whether in the form of a carbon tax or a cap-and-trade system. If the carbon price in a jurisdiction does not meet the federal minimum price, the federal government will step in and impose a carbon price that makes up the difference and return the revenue to the province or territory. In addition, provincial and territorial goals for reducing emissions must be at least as stringent as federal targets. Currently, Canada's four biggest provinces representing more than 80% of Canada's population (Ontario, Québec, Alberta and British Columbia) have carbon pricing in place

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

With regards to GHG emissions, In March 2004, the federal government announced the introduction of the Greenhouse Gas Emissions Reporting Program ("**GHGRP**"), which applies to large industrial GHG emitters in Canada. All facilities that emit the equivalent of 50,000 tonnes or more of CO2e per year are required to submit a report to Environment Canada. Facilities with emissions below the reporting threshold of 50,000 tonnes per year can voluntarily report their GHG emissions.

It is expected that additional 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. There remains ongoing uncertainty regarding Canada's short-term and long-term emissions reduction targets and how such targets will be achieved. 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.

British Columbia

The Corporation's GHG emissions directly subject the Corporation to proposed legislation regulating GHG emissions in British Columbia. The Government of British Columbia released an energy plan in February 2007 (the "**Energy Plan**") outlining a provincial environmental strategy reducing GHG emissions, which promotes investment in research and innovation, and world leadership in sustainable environmental management. To this end, the province has since implemented: an Innovative Clean Energy Fund; a new Net Profit Royalty Program; an Infrastructure Royal Credit Program; and a broad-based carbon tax on all fossil fuels consumed in the province (including natural gas flared at a wellhead or a processing facility). The British Columbia carbon tax is currently $30/tonne of CO_2 equivalent. The carbon tax is revenue neutral, in that carbon tax revenue funds personal and business tax cuts by the Government of British Columbia. The Energy Plan contemplates various other initiatives, including: the elimination of routine flaring at producing wells and processing facilities; tight gas, coalbed gas and other unconventional development incentives; implementation of a petroleum registry; an oil and gas technology transfer incentive program; and incentives for increased recoveries from existing reserves.

In 2008, the Government of British Columbia introduced and enacted the *Greenhouse Gas Reduction (Cap and Trade) Act* (the "**Cap and Trade Act**"), which provides the regulatory framework for the province's participation in the emissions cap-and-trade system proposed by Western Climate Initiative ("**WCI**"). The WCI is a partnership of seven U.S. states and four Canadian provinces, including British Columbia, Manitoba, Québec and Ontario, with the goal of reducing greenhouse gas emissions by 15 per cent below 2005 levels by 2020. Unlike the emissions intensity approach taken by the federal government and the Government of Alberta, the Cap and Trade Act (and the WCI regime) will establish an absolute cap on GHG emissions.

Reporting regulations came into force on January 1, 2010 requiring all British Columbia facilities emitting over 10,000 tonnes of CO_2 equivalents per year to report their emissions. Facilities reporting emissions greater than 25,000 tonnes of CO_2 equivalents per year are required to have their emissions reports verified by a third party. At present, the Corporation has no facilities subject to these regulations.

The Government of British Columbia is in the process of assessing whether or not it will proceed with plans to participate in the WCI regional greenhouse gas cap and trade system. Draft emissions trading regulations and offsets regulation have been posted by the British Columbia Climate Action Secretariat, but have yet to be finalized. Under the regulations, certain facilities would be required to meet established targets through a combination of emissions allowances issued by the Government of British Columbia and the purchase of emissions offsets generated through activities that result in a reduction in greenhouse gas emissions.

British Columbia's *Greenhouse Gas Industrial Reporting and Control Ac*t came into force on January 1, 2016. This Act was originally passed by the British Columbia legislature in November 2014 and enables performance standards to be established for industrial facilities or sectors. It currently sets a GHG emissions benchmark for liquefied natural gas (LNG) facilities, along with an emissions benchmark for coal-based electricity generation operations. Performance standards for other industrial facilities and sectors will likely be added later on. This Act also streamlines several aspects of existing GHG legislation into a single legislative and regulatory system, including the GHG reporting framework established under the *Greenhouse Gas Reduction (Cap and Trade) Act*. This legislation represents British Columbia's efforts to achieve its legislated GHG emission reduction target of 33% below 2007 levels by 2020. The Government of British Columbia estimates that five LNG plants in British Columbia will generate 13 million tonnes of GHG emissions, on top of the province's current annual GHG emissions of 62 million tonnes.

On August 19, 2016, the Government of British Columbia released its long awaited Climate Leadership Plan ("**BC Climate Plan**"). The BC Climate Plan, which updates the province's 2008 Climate Action Plan, contains 21 new actions to reduce emissions across the following sectors: (i) natural gas, (ii) transportation, (iii) forestry and agriculture, (iv) communities and built environment, and (v) public sector. The BC Climate Plan follows the release of the Climate Leadership Team's report in November 2015. While the BC Climate Plan reflects some recommendations made by the Climate Leadership Team and feedback received through public consultation and stakeholder engagement sessions, the BC Climate Plan bypasses British Columbia's 2020 target of achieving a reduction in GHG emissions of 33% below 2007 levels and instead charts a path for British Columbia to reach its 2050 target of 80% below 2007 levels. In addition, the Government of British Columbia has decided to keep the province's revenue neutral carbon tax at $30 per tonne until such time as the other provinces' various carbon pricing plans catch up to British Columbia.

The British Columbia legislation does not apply directly to any of the Corporation's facilities and is expected to have a negligible effect on the Corporation's operations and operating expenses.

Alberta

On July 1, 2007, the *Specified Gas Emitters Regulation* ("**SGER**") came into force under Alberta's *Climate Change and Emissions Management Amendment Act* requiring Alberta facilities which emit more than 100,000 tonnes of GHGs annually ("**Regulated Emitters**") to reduce their GHG emissions intensity by 12% (from average 2003-2005 levels). If a facility is not able to abate GHG emissions sufficiently to meet the reduction target, it may utilize the following compliance mechanisms: (i) emissions performance credits obtained from other regulated facilities; (ii) emissions offsets obtained from non-regulated facilities or projects which reduce or remove GHG emissions; or (iii) credits for contributions to the Climate Change and Emissions Management Fund. Regulated Emitters may choose any combination of these compliance mechanisms to comply with their target. At present, the Corporation does not believe that it owns any facilities subject to this Alberta regulation. The Alberta Government also published a new climate change action plan in January of 2008 wherein it set an objective to deliver a 50% reduction in GHG emissions by 2050 compared to business as usual, by employing: (i) mandatory carbon capture and storage ("**CCS**") for certain facilities and development across all industrial sectors; (ii) energy efficiency and conservation; and (iii) research and investment in clean energy technologies, including carbon separation technologies to assist CCS.

On June 25, 2015, the Government of Alberta renewed the SGER for a period of two years with significant amendments while Alberta's newly formed Climate Advisory Panel conducted a comprehensive review of the province's climate change policy. In 2015, Regulated Emitters are required to reduce their emissions intensity by 2% from their baseline in the fourth year of commercial operation, 4% of their baseline in the fifth year, 6% of their baseline in the sixth year, 8% of their baseline in the seventh year, 10% of their baseline in the eighth year, and 12% of their baseline in the ninth or subsequent years (to be increased to 15% as of January 1, 2016 and 20% as of January 1, 2017).

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

On November 22, 2015, as a result of the Climate Advisory Panel's Climate Leadership Report, the Government of Alberta announced its Climate Leadership Plan which introduced a carbon tax on all fuels that emit GHG emissions when combusted (some fuels are exempted) beginning January 1, 2017 at $20 per tonne of GHG emissions, increasing to $30 per tonne in January 2018. An oil sands specific approach was also introduced to replace the $30 per tonne of GHG emissions to further reduce emissions and promote carbon competitiveness rather than rewarding past intensity levels. A 100 megatonne per year limit for GHG emissions was introduced for oil sands operations, which currently emit roughly 70 megatonnes per year. This cap exempts new upgrading and cogeneration facilities, which are allocated a separate 10 megatonne limit. The existing SGER will be replaced for large industrial facilities with a *Carbon Competitiveness Regulation*, in which sector specific output-based carbon allocations will be used to ensure competitiveness.

Carbon pricing was also identified by the Climate Advisory Panel as the primary policy tool for reducing emissions in the province. On June 23, 2016, the Alberta legislature passed the *Climate Leadership Implementation Act* (Bill 20) which furthers the implementation of the Climate Leadership Plan. Details of Alberta's carbon pricing model were detailed in its April 2016 budget, which earmarks almost $8.5 billion to build and modernize major public infrastructure. Budget 2016 also allocated $634 million to various climate change initiatives in addition to funds for roads and bridges, flood recovery and municipal infrastructure support. The Act came into force on January 1, 2017 and empowers the provincial government to impose a carbon levy in the province. As of January 1, 2017, a $20 per tonne carbon levy will be applied to fuels that emit GHG when combusted. This levy will increase to $30 per tonne in 2018. Fuels covered by the levy include transportation and heating fuels such as diesel, gasoline, natural gas and propane. It will not apply directly to consumer purchases of electricity. Revenues from the carbon levy will be used for initiatives to reduce GHG emissions and to fund carbon rebates, as well as for investments in clean technology and green infrastructure. The carbon levy will also be used for an "adjustment fund" to help individuals and families, small business and First Nations adjust. Some fuels are exempt from the levy including marked gasoline and diesel used by farmers, natural gas produced and consumed on site by conventional producers, fuel used for inter-jurisdictional flights, and biofuels.

The new Alberta legislation does not apply directly to any of the Corporation's facilities and is expected to have a negligible effect on the Corporation's operations and operating expenses.

RISK FACTORS

An investment in the Corporation should be considered speculative due to the nature of the Corporation's involvement in the acquisition, exploration, development, production and marketing of oil and natural gas and due to its current stage of development. Oil and gas operations involve many risks which even a combination of experience and knowledge and careful project management may not be able to overcome. There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by the Corporation or that existing oil and gas reserves owned by the Corporation can be profitably produced and sold.

Volatility of Oil and Gas Prices and General Economic Conditions

The Corporation's results of operations and financial condition are dependent on the prevailing prices of crude oil and natural gas. Crude oil and natural gas prices have fluctuated dramatically in the recent past and are subject to fluctuations in response to relatively minor changes in supply, demand, market uncertainty and other factors that are beyond the Corporation's control. Crude oil and natural gas prices are affected by a number of factors including, but not limited to: the global and domestic supply of and demand for crude oil and natural gas; global and North American economic conditions; the actions of OPEC or individual producing nations; government regulation; political stability; the ability to transport commodities to markets; developments related to the market for liquefied natural gas; the availability and prices of alternate fuel sources; and weather conditions. In addition, significant growth in crude oil production 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, as well as contributing to fluctuations in the index price of oil and natural gas. All of these factors are beyond the Corporation's control and can result in a high degree of price volatility.

Fluctuations in currency exchange rates further compound this volatility when commodity prices, which are generally set in U.S. dollars, are stated in Canadian dollars. The Corporation's financial performance also depends on revenues from the sale of commodities which differ in quality and location from underlying commodity prices quoted on financial exchanges.

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

Any material or sustained decline in commodity prices could result in a reduction of the Corporation's net production revenue and funds flow from operations. The economics of producing from some wells may change as a result of such lower prices, which could result in reduced production of oil or gas and a reduction in the volumes and value of the Corporation's reserves. The Corporation 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 funds flow from operations and a reduction in its oil and gas acquisition, development and exploration activities.

Crude oil and natural gas prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and the demand of these commodities due to the current state of the world and national economies, the actions of OPEC or individual producing nations, weather patterns, as well as unforeseeable geopolitical events. 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 economic return on acquisitions and development projects.

In addition, bank borrowings available to the Corporation are, in part, determined by the Corporation's borrowing base. A sustained material decline in commodity 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, as well as curtailment of the Corporation's investment programs.

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

Substantial Capital Requirements and Liquidity

The Corporation anticipates that it will make substantial capital expenditures for the acquisition, exploration, development and production (including facility acquisition or construction) of oil and natural gas reserves in the future. If the Corporation does not have, or is unable to increase, revenues or reserves in the future, the Corporation may have limited ability to maintain funds flow and to attract the capital necessary to undertake or complete future drilling programs. There can be no assurance that debt or equity financing, or cash generated by operations, or from the sale of non-core assets, will be available or sufficient to meet those requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Corporation. Moreover, future activities may require the Corporation to alter its capitalization significantly. The inability of the Corporation to access sufficient capital for its operations could have a material adverse effect on the Corporation's financial condition, results of operations or prospects.

Credit Facility Risk

The current Credit Facility is subject to renewal by April 28, 2017. There is a risk that the Credit Facility will not be renewed for the same amount or on the same terms or that the borrowing base will not be increased as a result of production growth to date and forecasted production growth. Although the Corporation believes that the Credit Facility will be sufficient for its immediate requirements, there can be no assurance that the amount will be adequate for the Corporation's future financial obligations including its capital expenditure program, or that additional funds will be available under the Credit Facility or from other sources on terms acceptable to the Corporation.

The Corporation is required to comply with its covenants under the Credit Facility. In the event that the Corporation does not comply with its covenants under the Credit Facility, access to the Credit Facility could be restricted or accelerated repayment could be required by its lenders and debt service costs would likely increase. Although the Corporation believes it is in compliance with existing covenants, compliance may not be sustainable or covenants may become increasingly onerous.

Additional Funding Requirements

The Corporation's future funds flow 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 future revenues decrease as a result of lower oil and natural gas prices or otherwise, it will affect the Corporation's ability to attract the necessary capital to identify and increase reserves or to maintain its production. If the Corporation's funds flow from operations is not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing or proceeds from asset sales will be available to meet this funding shortfall or will be available on terms acceptable to the Corporation.

Capital and Lending Markets

As a result of general economic uncertainties and, in particular, the low price for natural gas, the Corporation, along with other entities having substantial exposure to natural gas, may have reduced access to bank debt and to equity. As future capital expenditures will be financed out of funds flow, bank borrowings if available, and possible equity issues, 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 and the Corporation's securities in particular.

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

Based on expected funds generated from operations and bank credit availability, the Corporation believes it has sufficient funds available to support its projected capital expenditures. However, if funds generated from operations are lower than expected or capital costs for these projects exceed current estimates, or if the Corporation incurs major unanticipated expenses related to development or maintenance of its existing properties, it may be required to seek additional capital to maintain its capital expenditures at planned levels. Failure to obtain any financing necessary for the Corporation's capital expenditure plans may result in a delay in development or production on the Corporation's properties. The Corporation will also consider selling non-core assets to support investment programs.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

From time to time the Corporation makes acquisitions and dispositions of businesses and assets that occur in the ordinary course of business. Achieving the benefits of acquisitions depends in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner, as well as realizing the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Corporation. The integration of acquired businesses may require substantial management effort, time and resources and may divert management's focus from other strategic opportunities and operational matters. Management continually assesses the value and contribution of individual properties and other assets. In this regard, non-core assets are periodically disposed of, so that the Corporation can focus its efforts and resources more efficiently. Proceeds on the sale of non-core assets may be less than anticipated, affecting the corporation's capital availability.

Royalties

There can be no assurance that the federal government and the provincial governments of Alberta and British Columbia will not adopt new royalty regimes or modify the existing royalty regimes which may have an effect on the economics of the Corporation's projects. An increase in royalties would reduce the Corporation's funds flow and could make future capital investments, or the Corporation's operations, less economic. Frequent changes to royalty regimes have created uncertainty surrounding the ability to accurately estimate future royalties and, correspondingly, funds flow, resulting in additional volatility and uncertainty for producers, including the Corporation.

Competition

The petroleum industry is competitive in all its phases. The Corporation competes with numerous other participants for the acquisition of oil and natural gas properties, for access to third party processing and transportation capacity and in the marketing of oil and natural gas. The Corporation's competitors include companies which have greater financial resources, staff, access to land and facilities than those of the Corporation. The Corporation's ability to increase reserves in the future will depend not only on its ability to develop its present properties, but also on its ability to identify and acquire suitable producing properties or prospects for exploratory drilling. Competitive factors in the distribution and marketing of oil and natural gas include price, methods of delivery and reliability of delivery.

The marketability of oil and natural gas acquired or discovered is affected by numerous factors beyond the control of the Corporation. These factors include reservoir characteristics, market fluctuations, the proximity, capacity and access to oil and natural gas pipelines and processing facilities as well as government regulation. Oil and natural gas operations (exploration, drilling, well completions and tie-ins, production, facility operation, distribution, 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. The Corporation's oil and natural gas operations are also subject to compliance with increasingly demanding federal, provincial and local laws and regulations controlling the discharge of pollutants into the environment or otherwise relating to the protection of the environment. Although the Corporation believes that it is in material compliance with current applicable environmental regulations, changing government regulations may have an adverse effect on the Corporation. See "*Industry Conditions - Environmental Protection Requirements*" and "*Risk Factors – International and Domestic GHG Regulations*".

Operating Risks

Oil and natural gas exploration is subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, cratering, oil spills and releases of possibly sour natural gas, each of which could result in substantial damage to oil and natural gas wells, producing facilities, other property and the environment or in personal injury and fatalities. In accordance with industry practice, the Corporation is not fully insured against all of these risks, nor are all such risks insurable or even identifiable. Although the Corporation maintains liability insurance in an amount which it considers adequate, the nature of these risks is such that liabilities could exceed policy limits, in which event the Corporation could incur significant costs that could have a materially adverse effect upon its financial condition. Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including premature decline of reservoirs, the invasion of water into producing formations, inability to access production or facility sites, access to third party pipelines and facilities, pipeline and facilities damage and a range of other risks, some of which may not be foreseeable. In addition, economic conditions may affect the solvency of suppliers, customers and partners, possibly resulting in financial loss and/or operational disruption.

Hedging Activities

The Corporation may enter into agreements to receive fixed or collared prices on its oil and natural gas production as well as other derivative instruments 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 will record losses from hedging activities based on mark-to-market measurement.

Availability of Equipment

Oil and natural gas exploration and development activities are dependent on the availability of drilling, completion and related equipment as well as experienced and competent crews in the particular areas where such activities will be conducted. Demand for equipment or access restrictions may affect the availability of such equipment to the Corporation and may delay exploration and development activities. Further, to the extent the Corporation is not the operator of its oil and gas properties, the Corporation will be dependent on such operators for the timing of activities related to such properties and will be largely unable to direct or control the activities of the operators.

Environmental and Operational Matters

Many aspects of the oil and natural gas business present environmental risks and hazards, including the risk that the Corporation may be in non-compliance with an environmental law, regulation, or without a necessary permit, licence, or other regulatory approval, possibly unintentionally. Such risks may expose the Corporation to fines or penalties, third party liabilities or to the requirement to terminate operations or remediate, each of which could be material. The operational hazards associated with possible blowouts, accidents, spills, gas leaks, fires, or other damage to a well or a pipeline may require the Corporation to incur costs and delays to undertake corrective actions, and could result in environmental damage or contamination for which the Corporation could be liable for remediation costs and fines imposed by regulatory agencies. Oil and gas operations are also subject to specific operational risks which may have material operational and financial effect on the Corporation should they occur, such as drilling into unexpected formations or unexpected pressures, premature decline of reservoirs, and water invasion into producing formations. In addition, many of the Corporation's wells produce sour gas, which necessitates the use of equipment built to sour gas specifications. In addition to being subject to stringent regulation by the provincial regulator with respect to emergency response plans, public safety and application procedures and requirements, sour gas operations are subject to special control and handling policies which are codified in the Corporation's Corporate Health and Safety Manual.

Although the Corporation maintains liability insurance consistent with prudent industry practice, the nature of environmental risks is such that they may exceed commercially reasonable insurance coverage. In this event the Corporation could incur significant costs which would be funded from cash resources and which may have an adverse effect on the Corporation's ability to finance future investment or continue in business.

There is currently industry uncertainty as to the potential application and extent of GHG reduction requirements and potential compliance options. As a result, it is not possible to predict the operational and financial effects of future GHG emissions laws, if any, applicable to the Corporation.

Liability Management

Alberta and British Columbia have developed liability management programs designed to protect taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licensee or permit holder can no longer meet its obligations. These programs generally involve an assessment of the ratio of a licensee's deemed assets to deemed liabilities. If a licensee's deemed liabilities exceed its deemed assets, a security deposit is required. Changes of the ratio of the Corporation's deemed assets to deemed liabilities or changes to the requirements of liability management programs may result in significant increases to the security that must be posted. In addition, the liability management system may prevent or interfere with the Corporation's ability to acquire or dispose of assets as both the vendor and the purchaser of oil and gas assets must be in compliance with the liability management programs (both before and after the transfer of the assets) for the applicable regulatory agency to allow for the transfer of such assets. See "*Industry Conditions - Liability Management Rating Programs*".

Climate Change

The Corporation's exploration and production facilities and other operations and activities emit greenhouse gases which may require the Corporation to comply with GHG emissions legislation at the provincial or federal level. Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are put in place. Some of the Corporation's facilities may be subject to future regional, provincial and/or federal climate change regulations to manage GHG emissions. Prior to adopting the Paris Agreement, Canada set an INDC target of a 30% reduction from 2005 levels in GHG emissions by 2030. In 2018, Canada along with the other member parties will convene a facilitative dialogue to assess their collective efforts in relation to their progress towards the long-term goal. The outcomes of this dialogue will likely inform future climate policies and actions.

The direct or indirect costs of compliance with future regulations may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In addition, concerns about climate change have resulted in a number of environmental activists and members of the public opposing the continued exploitation and development of fossil fuels. Given the evolving nature of the debate related to climate change and the control of GHG and resulting requirements, it is not possible to predict the effect on the Corporation and its operations and financial condition. See "*Industry Conditions - Environmental Protection Requirements*".

Exchange Rate Fluctuations

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, during the period of such agreements, the Corporation would not benefit from the changing exchange rate.

Title Reviews

Although title reviews will be completed according to industry standards prior to the purchase of most oil and natural gas 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 claim of the Corporation which could result in a reduction of the revenue received by the Corporation from exploitation of the property.

Reserves Estimate Uncertainty

There are numerous uncertainties inherent in estimating quantities of reserves and future net revenue to be derived therefrom, including many factors that are beyond the control of the Corporation. The reserves and future net revenue information set forth in this AIF represent estimates only. The reserves and estimated future net revenue from the Corporation's properties have been independently evaluated effective December 31, 2016 by InSite. These evaluations include a number of assumptions relating to factors such as initial production rates, production decline rates, ultimate recovery of reserves, timing and amount of capital expenditures, marketability of production, future prices of oil and natural gas, operating costs and royalties and other government levies that may be imposed over the producing life of the reserves. These assumptions were based on price forecasts in use at the date the relevant evaluations were prepared and many of these assumptions are subject to change and are beyond the control of the Corporation. Actual production and future net revenue derived therefrom will vary from these evaluations, and such variations could be material. The foregoing evaluations are based in part on the assumed success of exploitation activities intended to be undertaken in future years. The reserves and estimated future net revenue 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 evaluations.

Production

Production of oil and natural gas reserves at an acceptable level of profitability may not be possible during periods of low commodity prices. The Corporation will attempt to mitigate this risk by focusing on higher netback opportunities and will act as operator where possible, thus allowing the Corporation to manage costs, timing, method and marketing of production. Production risk is also addressed by concentrating exploration and development efforts in regions where infrastructure is or will be Storm owned or readily accessible at an acceptable cost. In periods of low commodity prices, the Corporation will shut in production, either temporarily or permanently, if field operating netbacks are sub-economic.

Production is also dependent in part on access to third party facilities with the result that production may be reduced by outages, accidents, maintenance programs and similar interruptions outside of the Corporation's control.

Storm's contracted gas processing capacity at third party facilities was approximately 80% of total raw gas production in the fourth quarter of 2016 with the remaining portion relying on access to interruptible capacity. There is a risk that the uncontracted, interruptible portion could be reduced or shut in if capacity is allocated to other parties. Storm is working to increase the amount of raw gas production subject to contract. In the absence of additional contractual capacity, production growth will be delivered under interruptible terms.

Marketing Risks

Markets for future production of crude oil and natural gas are outside the Corporation's capacity to control or influence and can be affected by events such as weather, climate change, regulation, regional, national and international supply and demand imbalances, facility and pipeline access, geopolitical events, currency fluctuation, introduction of new or termination of existing supply arrangements, as well as downtime due to maintenance or damage, either to owned or third party facilities and pipelines. The Corporation will attempt to mitigate these risks as follows:

- Properties are developed in areas where there is access to processing and pipeline or other transportation infrastructure, and, where possible, owned by the Corporation.
- The Corporation will delay drilling or tie-in of new wells or shut in production if acceptable pricing cannot be realized.
- The Corporation constantly assesses the various markets into which production can be sold and if possible will direct production to markets offering the most attractive returns.
- The Corporation endeavours to secure access to facilities and pipelines under contracts setting volumes, prices and term.

Storm has contracted pipeline transportation capacity for approximately 72 Mmcf per day of natural gas sales volumes in the first quarter of 2017 with the remaining portion relying on access to interruptible capacity. There is a risk that the uncontracted, interruptible portion could be reduced or shut in during partial outages or if capacity is allocated to other parties.

The Corporation's product profile comprises a large and growing percentage of natural gas. Pricing and access to markets has been affected by the growth of domestic gas production in the United States. When, if ever, access to historical markets in the United States may improve, is not predictable. Further, development of certain natural gas reserves in Canada is to a degree underwritten by the expectation that new Pacific Rim export markets will be accessed through the establishment of LNG liquefaction facilities on Canada's west coast. When such facilities will be completed, if ever, cannot be predicted.

Financial Risks

The Corporation may enter into transactions to acquire assets or the shares of other corporations. These transactions may be financed partially or wholly with debt, which may result in the Corporation's debt exceeding acceptable levels. Depending on future exploration and development plans, the Corporation may require financing additional to existing resources which may not be available or, if available, may not be available on favourable terms.

Trade Relations

The government of the United States has publicly announced its interest in renegotiating NAFTA with Canada and Mexico. NAFTA currently prohibits government intervention in the normal operation of the North American energy market, whether in the form of price discrimination through the imposition of export taxes or the direct disruption of supply channels. In addition, NAFTA ensures that North American customers have equal access to oil produced in either country, ensuring a broad demand base for the Corporation's oil and natural gas. It is uncertain whether the government of the United States may successfully change or alter the terms of the NAFTA, and what effects those changes may have on the Corporation.

On January 23, 2017, United States President Trump signed a Presidential Memorandum directing the United States Trade Representative to withdraw the United States as a signatory to the TPP and to permanently withdraw the United States from TPP negotiations. It is uncertain whether the remaining signatories to the TPP will ratify the TPP or will seek to change or alter the terms of the TPP, and what effects the TPP may have on the Corporation.

Further, unlegislated proposals from the government of the United States have contemplated prohibitive actions against foreign businesses competing in the United States economy. It is uncertain whether the government of the United States will proceed with any proposed or contemplated actions, or the effects those actions may have on the Corporation.

Geo-Political Risks

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

In addition, the Corporation's oil and natural gas properties, wells and facilities could be the subject of 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. The Corporation does not have insurance to protect against the risk from terrorism.

The remoteness of the Corporation's producing properties, gathering systems and facilities makes them vulnerable to damage or blockade by militant groups seeking to disrupt the Corporation's operations or industry activity generally.

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.

Dependence on Key Personnel

The Corporation's success depends in large measure on certain key personnel including Brian Lavergne, Donald G. McLean, Robert S. Tiberio, John J. Devlin, Jamie P. Conboy, H. Darren Evans and Bret A. Kimpton. The loss of the services of such key personnel could have an adverse effect on the Corporation. The Corporation does not have key person insurance in effect for management. The contributions of these individuals to the immediate operations of the Corporation are likely to be of central importance. Further, 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. Readers must rely upon the ability, expertise, judgment, discretion, integrity and good faith of the management of the Corporation.

Dilution

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

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 effect on the Corporation's assets, liabilities, business, financial condition and results of operations.

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights in portions of western Canada. The Corporation is not aware that any specific 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.

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 the 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.

Third Party Credit Risk

The Corporation is or 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, counterparties to financial instruments and other parties. In the event such entities fail to meet their contractual obligations, such failures could have a material adverse effect on the Corporation, its funds flow from operations and its liquidity structure.

Expansion into New Activities

The operations and expertise of the Corporation's management are currently focused primarily on natural gas and NGL production, exploration and development in the Western Canada Sedimentary Basin. 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.

Forward-Looking Statements May Prove Inaccurate

Readers are cautioned not to place undue reliance on forward-looking information in this AIF. 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. See "*Notes Regarding Forward-Looking Statements*".

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, the Corporation 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.

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 the Corporation during, or related to, the Corporation's most recently completed financial year other than InSite, the independent reserve evaluators, and Ernst & Young LLP, the Corporation's auditors.

None of the principals of InSite had any registered or beneficial interests, direct or indirect, in any securities or other property of the Corporation or its 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.

Ernst & Young LLP is independent of the Corporation in accordance with the Chartered Professional Accountants of Alberta Rules of Professional Conduct.

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

AUDITORS, TRANSFER AGENT AND REGISTRAR

The auditors of the Corporation are Ernst & Young LLP, Chartered Professional Accountants, 2200, 215 - 2nd Street S.W., Calgary, Alberta, T2P 1M4.

The transfer agent and registrar for the Common Shares of the Corporation is Alliance Trust Company at its office in Calgary, Alberta.

ADDITIONAL INFORMATION

Additional information relating to the Corporation may be found on SEDAR at www.sedar.com. 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 information circular for the most recent annual meeting of shareholders that involved the election of directors.

Additional financial information is provided in the Corporation's audited consolidated financial statements, and Management's Discussion and Analysis for the year ended December 31, 2016. Management and auditors' reports on the financial statements are dated March 2, 2017 and Management's Discussion and

Analysis is dated March 2, 2017. These documents are available on the SEDAR website at www.sedar.com and on the Corporation's website at www.stormresourcesltd.com.

APPENDIX A
FORM 51-101F2 - REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

Terms to which a meaning is ascribed in NI 51-101 have the same meaning in this form.[1]

REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

To the board of directors of Storm Resources Ltd. (the "**Company**"):

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

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

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

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

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

Independent Qualified Reserves Evaluator or Auditor	Description and Preparation Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate)			
			Audited	**Evaluated**	**Reviewed**	**Total**
InSite Petroleum Consultants Ltd.	Evaluation of the P&NG Reserves of the Company as of December 31, 2016 and dated February 24, 2017	Canada	-	$758,134,900	-	$758,134,900
Totals			-	$758,134,900	-	$758,134,900

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

[1] For the convenience of readers, CSA Staff Notice 51-324 Glossary to NI 51-101 – *Standards of Disclosure for Oil and Gas Activities* ("**NI 51-101**") sets out the meanings of terms that are printed in italics in sections 1 and 2 of this Form or in NI 51-101, Form 51-101F1, Form 51-101F3 or Companion Policy 51-101CP.

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

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

Executed as to our report referred to above:

InSite Petroleum Consultants Ltd.
Calgary, Alberta, Canada

(signed) "D. L. Paddock"
D. L. Paddock, P.Eng.
Managing Director

March 31, 2017

APPENDIX B
FORM 51-101F3 - REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION

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

InSite Petroleum Consultants Ltd., independent qualified reserves evaluators, has evaluated the Company's reserves data. The report of the independent qualified reserves evaluators will be filed with securities regulatory authorities concurrently with this report.

The Reserves Committee of the board of directors of the Company has:

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

(b) met with the independent qualified reserves evaluators 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 of the Company has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors of the Company has, on the recommendation of the Reserves Committee, approved:

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

(e) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluators on the reserves data; and

(f) the content and filing of this report.

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

(signed) "Brian Lavergne"	*(signed) "Donald G. McLean"*
Brian Lavergne President and Chief Executive Officer	Donald G. McLean Chief Financial Officer
(signed) "Matthew J. Brister"	*(signed) "P. Grant Wierzba"*
Matthew J. Brister Director	P. Grant Wierzba Director and Chairman of the Reserves Committee

March 31, 2017