

RETURN ENERGY INC.

Annual Information Form

Financial Year Ended December 31, 2019

Dated April 7, 2020

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CONVENTIONS

Unless otherwise indicated, references herein to “\$” or “dollars” are to Canadian dollars. All financial information with respect to the Corporation has been presented in Canadian dollars in accordance with generally accepted accounting principles in Canada. The information in this annual information form (“**Annual Information Form**”) is stated as at December 31, 2019, unless otherwise indicated. For an explanation of the capitalized terms and expressions and certain defined terms, please refer to the section of this Annual Information Form titled “*Definitions*”.

ABBREVIATIONS

	Oil and Natural Gas Liquids		Natural Gas
Bbl	barrel	Mcf	thousand cubic feet
Bbls	barrels	Mmcf	million cubic feet
BOPD	barrel of oil per day	Mcf/d	thousand cubic feet per day
Mbbl	thousand barrels	Mmcf/d	million cubic feet per day
Bbls/d	barrels per day		
NGLs	natural gas liquids		
LNG	liquified natural gas		
Other			
°C	degree Celsius		
API	an indication of the specific gravity of crude oil measured on the American Petroleum Institute gravity scale. Liquid petroleum with a specified gravity of 28° API or higher is generally referred to as light crude oil.		
BOE	barrel of oil equivalent of natural gas and crude oil on the basis of 1 BOE for 6 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		
CO ₂ e	carbon dioxide equivalent		
GHG	greenhouse gas		
IFRS	International Financial Reporting Standards, accounting standards issued by the IFRS Foundation and the International Accounting Standards Board		
m ³	cubic metres		
Mt	megaton		
WCS	Western Canadian Select, the reference price paid in Canadian dollars at Hardisty, Alberta for crude oil of standard grade		
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade		

DEFINITIONS

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

“**2019 Private Placement**” has the meaning specified in “*General Development of the Business – Three Year History – Financial Year Ended December 31, 2019*”;

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

“**AER**” means the Alberta Energy Regulator;

“**Bill C-69**” means Bill C-69, *An Act to enact the Impact Assessment Act and the Canadian Energy Regulator Act, to amend the Navigation Protection Act and to make consequential amendments to other Acts*, issued by the Canadian federal government;

“**Board**” means the board of directors of Return;

“**CER**” means the Canadian Energy Regulator;

“**CER Act**” means the *Canadian Energy Regulator Act* (Canada), S.C. 2019, c.28;

“**COGE Handbook**” means the Canadian Oil and Gas Evaluation Handbook prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum;

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

“**Consolidation**” has the meaning specified in “*The Corporation*”;

“**Corporation**” or “**Return**” means Return Energy Inc.;

“**CPTPP**” means the Comprehensive and Progressive Agreement for Trans-Pacific Partnership;

“**Initial Investors**” has the meaning specified in “*General Development of the Business – Three Year History – Financial Year Ended December 31, 2019*”;

“**LLR Program**” has the meaning specified in “*Narrative Description of the Business – Industry Conditions – Liability Management Rating Programs*”;

“**Market Price**” has the meaning specified in “*General Development of the Business – Three Year History – Financial Year Ended December 31, 2019*”;

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

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

“**New Board**” has the meaning specified in “*General Development of the Business – Three Year History – Financial Year Ended December 31, 2019*”;

“**New Management Team**” has the meaning specified in “*General Development of the Business – Three Year History – Financial Year Ended December 31, 2019*”;

“**NI 51-101**” means National Instrument 51-101 – *Standard of Disclosure for Oil and Gas Activities* adopted by the Canadian Securities Administrators;

“**NI 51-102**” means National Instrument 51-102 – *Continuous Disclosure Obligations* adopted by the Canadian Securities Administrators;

“**OGCA**” has the meaning specified in “*Narrative Description of the Business – Industry Conditions – Environmental Regulation – Alberta*”;

“**OPEC**” means the Organization of Petroleum Exporting Countries, and “**OPEC+**” refers to OPEC plus Russia, Azerbaijan, Bahrain, Brunei, Kazakhstan, Malaysia, Mexico, Oman, South Sudan and Sudan;

“**Options**” means stock options to purchase Common Shares granted pursuant to the Corporation’s stock option plan;

“**Orphan Well Fund**” has the meaning specified in “*Narrative Description of the Business – Industry Conditions – Liability Management Rating Programs*”;

“**Preferred Shares**” means preferred shares in the capital of Return;

“Recapitalization Transaction” has the meaning specified in *“General Development of the Business – Three Year History – Financial Year Ended December 31, 2019”*;

“Recap Warrant” has the meaning specified in *“General Development of the Business – Three Year History – Financial Year Ended December 31, 2019”*;

“Redwater” has the meaning specified in *“Narrative Description of the Business – Industry Conditions – Liability Management Rating Programs”*;

“Series I Preferred Shares” means non-interest bearing, non-voting series I Preferred Shares;

“Shareholders” means holders of Common Shares;

“Special Shares” means non-voting, redeemable, retractable special Preferred Shares;

“Sproule” means Sproule Associates Limited;

“Sproule Report” has the meaning specified in *“Statement of Reserves Data and Other Oil and Gas Information – Reserves Data (Forecast Prices and Costs)”*;

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

“TSXV” means the TSX Venture Exchange;

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

“USMCA” means the United States-Mexico-Canada Agreement;

“Vertex Offering” has the meaning specified in *“General Development of Business – Three Year History – Financial Year Ended December 31, 2017”*;

“Warrants” means Common Share purchase warrants issued by Return pursuant to private placements, acquisitions and prospectus offerings; and

“Winslow” means Winslow Resources Inc., a corporation which is wholly owned by Return and subsisting under the ABCA.

SPECIAL NOTE REGARDING FORWARD LOOKING STATEMENTS AND OTHER INFORMATION

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

Forward-looking statements or information in this Annual Information Form include, but are not limited to, the characteristics of the Corporation’s oil and natural gas interests, reserve quantities and the discounted present value of future net cash flows from such reserves, net revenue, future production levels, projection of market prices, capital expenditures, exploration plans, development plans, growth prospects, acquisition and disposition plans and the timing

thereof, operating and other costs, worldwide supply and demand for petroleum products, royalty rates, treatment under governmental regulatory regimes and tax laws, future revenues and costs (including royalties) and revenues and costs per commodity unit, oil and natural gas production levels, ability to meet current and future obligations, future tax liabilities and future use of tax pools and losses, future decommissioning costs, the ability to obtain financing on acceptable terms or at all and currency, exchange and interest rates. In addition, this Annual Information Form may contain forward-looking statements attributed to third party industry sources.

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

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

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

- general economic conditions in Canada and globally;
- the ability of management to execute its business plan;
- fluctuations in the price of oil and natural gas, interest and exchange rates;
- risks inherent in the oil and gas industry, such as operational risks and market demand;
- governmental regulation of the oil and gas industry, including environmental regulation;
- uncertainty in amounts and timing of royalty payments;
- actions taken by governmental authorities, including increases in taxes and changes in government regulations and incentive programs;
- geological, technical, drilling and processing problems;
- exploration and development activities are capital intensive and involve a high degree of risk;
- risks and uncertainties involving geology of oil and gas deposits;
- risks inherent in marketing operations, including credit risk;
- the uncertainty of reserves estimates and reserves life;
- the uncertainty of estimates and projections relating to production, costs and expenses;
- potential delays or changes in plans with respect to exploration or development projects or capital expenditures;
- availability of sufficient financial resources to fund the Corporation's capital expenditures;
- unanticipated operating events which could reduce production or cause production to be shut-in or delayed;
- hazards such as fire, explosion, blowouts, cratering and spills, each of which could result in substantial damage to wells, production facilities, other property and the environment or in personal injury;
- encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations;
- the ability to add production and reserves through development and exploration activities;
- general economic and business conditions;
- the possibility that government policies or laws, including laws and regulations related to the environment, may change or governmental approvals may be delayed or withheld;
- uncertainty in amounts and timing of royalty payments;
- uncertainties inherent in estimating quantities of oil and natural gas reserves and cash flows to be derived therefrom;
- failure to obtain industry partner and other third party consents and approvals, as and when required;
- stock market volatility and market valuations;

- competition for, among other things, capital, acquisition of reserves, undeveloped land and skilled personnel;
- the availability of capital on acceptable terms or at all;
- failure to realize the anticipated benefits of acquisitions and dispositions; and
- the other factors considered under “Risk Factors” below.

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

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

Readers are cautioned that the foregoing lists of factors are not exhaustive. The forward-looking statements contained herein, and the documents incorporated by reference herein, are expressly qualified by this cautionary statement. Readers should also carefully consider the matters discussed under the heading “Risk Factors” below.

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

Non-IFRS Measures

This AIF contains certain financial measures, including “operating netback (loss)” and “aggregate sales”, which do not have standardized meanings prescribed by IFRS. As these non-IFRS financial measures are commonly used in the oil and gas industry, the Corporation believes that their inclusion is useful to investors. The reader is cautioned that these amounts may not be directly comparable to measures for other companies where similar terminology is used.

The Corporation considers “operating netback (loss)” a key measure as it demonstrates corporate profitability relative to current commodity prices. “Operating netback (loss)”, which has no IFRS equivalent, is calculated on a per BOE basis by deducting operating expenses from total revenue, which is comprised of oil and gas sales, net of royalties, and processing and other revenue. “Aggregate sales” refers to total oil and gas sales revenue, before royalties.

Caution Respecting BOE

In this Annual Information Form, the abbreviation BOE means a barrel of oil equivalent on the basis of 1 BOE to 6 Mcf of natural gas when converting natural gas to BOEs. **BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf to 1 BOE is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio of oil compared to natural gas based on currently prevailing prices is significantly different than the energy equivalency conversion ratio of 6 Mcf to 1 BOE, utilizing a conversion ratio of 6 Mcf to 1 BOE may be misleading as an indication of value.**

THE CORPORATION

General

The Corporation was incorporated under the ABCA as “Dualet Energy International Inc.” on March 20, 2006. On May 24, 2006, the Corporation’s share structure was amended by way of a court-approved plan of arrangement (the “**Arrangement**”) under section 193 of the ABCA. Under the Arrangement, the articles of the Corporation were amended to: (a) remove all share transfer restrictions in the articles of the Corporation; and (b) create and authorize the Corporation to issue an unlimited number of Special Shares. On December 20, 2016, the Corporation consolidated its issued and outstanding Common Shares on the basis of ten (10) pre-consolidation Common Shares for one (1) post-consolidation Common Share (the “**Consolidation**”) and changed its name to “Return Energy Inc.”.

The Corporation is engaged in the exploration for and development and production of petroleum and natural gas properties in the Western Canadian Sedimentary Basin with a focus on the Peace River Arch area in northwest Alberta.

As of the date hereof, the Corporation is a reporting issuer in the Provinces of Alberta, British Columbia, Manitoba, Saskatchewan, Ontario and Quebec, and the Common Shares are listed on the TSXV under the trading symbol “RTN”.

The Corporation’s head office is located at 202, 1201 – 5th Street S.W., Calgary, Alberta T2R 0Y6. The registered office of the Corporation is located at 4300 Bankers Hall West, 888 – 3rd Street S.W., Calgary, Alberta T2P 5C5.

Inter-corporate Relationships

As at December 31, 2019 and the date hereof, Return has one wholly-owned subsidiary, Winslow, a corporation subsisting under the ABCA. The head office of Winslow is located at 202, 1201 – 5th Street S.W., Calgary, Alberta T2R 0Y6 and the registered office of Winslow is located at 4300 Bankers Hall West, 888 – 3rd Street S.W., Calgary, Alberta T2P 5C5.

GENERAL DEVELOPMENT OF THE BUSINESS

Three Year History

Financial Year Ended December 31, 2019

On November 21, 2019, the Corporation entered into a definitive reorganization and investment agreement with Fotis Kalantzis and Richard F. McHardy (the “**Initial Investors**”) which provided for: (a) a non-brokered private placement for gross proceeds of up to \$25.0 million (the “**2019 Private Placement**”); and (b) the appointment of a new management team (the “**New Management Team**”) and new board of directors (the “**New Board**”) of Return (collectively, the “**Recapitalization Transaction**”). The New Management Team is led by Richard F. McHardy as Executive Chairman and Fotis Kalantzis as President and Chief Executive Officer, Geri Greenall as Chief Financial Officer, Mark Hodgson as Vice President, Corporate Development, Thanos Natras as Vice President, Exploration, Craig Martin as Vice President, Operations and Brendan Paton as Manager, Engineering. The New Board is comprised of Richard F. McHardy, Fotis Kalantzis, Donald Archibald, Reginald Greenslade, Kevin Overstrom and Tamara MacDonald. Sanjib (Sony) Gill was appointed as Corporate Secretary. See “*Directors and Officers – Directors and Officers as at the Date Hereof*” below.

The closing in respect of the 2019 Private Placement was completed on December 19, 2019 (the “**Closing**”) with the Corporation issuing a total of 879,650,000 Common Shares and 1,620,350,000 units (the “**Recap Units**”) of the Corporation at a price of \$0.01 per Common Share and Recap Unit, respectively, for aggregate gross proceeds of \$25.0 million. The Recap Units issued under the 2019 Private Placement were issued to the New Management Team, the New Board and certain additional subscribers identified by such persons. Each Recap Unit was comprised of one Common Share and one Warrant (each, a “**Recap Warrant**”). Each Recap Warrant entitles the holder to purchase one Common Share at a price of \$0.01 (the “**Exercise Price**”) for a period of five years. The Recap Warrants vest and become exercisable as to one third upon the 10-day weighted average trading price of the Common Shares (the “**Market Price**”) equaling or exceeding 100% of the Exercise Price, an additional one-third upon the Market Price

equaling or exceeding 150% of the Exercise Price and a final one-third upon the Market Price equaling or exceeding 200% of the Exercise Price. Following the Closing, the appointment of the New Management Team and the New Board was completed.

On March 29, 2019, the Corporation closed a disposition of certain non-core petroleum and natural gas assets located at Valhalla, Alberta, for cash proceeds of \$214,793 after closing adjustments.

On March 25, 2019, the Corporation appointed an independent committee to undertake a broad review of potential alternatives to enhance shareholder value (the “**Review**”) and engaged Sayer Energy Advisors as its exclusive financial advisors in connection with the Review.

Financial Year Ended December 31, 2018

During the year ended December 31, 2018, the Corporation disposed of certain non-core land and oil assets for gross proceeds of \$352,059.

On February 12, 2018, through its wholly-owned subsidiary, Winslow, the Corporation commenced drilling operations at its Rycroft property north of Grande Prairie, Alberta, to test a northwest extension of the Rycroft Charlie Lake “S” pool from one of the Corporation’s then producing oil wells. On April 9, 2018, the Corporation announced completion of the initial drilling and completion program with the successful northerly extension of the Braeburn dolomite of the Charlie Lake ‘S’ pool, as evidenced with the drilling of an initial test well, in addition to confirming the presence of commercial light oil in the overlying Charlie Lake dolomitic siltstone encountered through the drilling of a second test well.

On January 11, 2018, the Corporation granted 5,000,000 Options to certain of its directors, officers, employees and consultants. The Options had an exercise price of \$0.10 per Common Share, expired on January 10, 2023 and vested on a one-half basis on each of the first and second anniversaries of January 10, 2018. Such Options were voluntarily surrendered to the Corporation for cancellation on December 19, 2019 in connection with the Recapitalization Transaction. For more information, see “*Financial Year Ended December 31, 2019*”, above.

Financial Year Ended December 31, 2017

On December 27, 2017, the Corporation closed a non-brokered private placement (the “**Vertex Offering**”) of 66,666,666 units of the Corporation (the “**Vertex Units**”) at a price of \$0.075 per Vertex Unit, all of which were issued to Vertex Managed Value Portfolio (“**VMVP**”), a fund managed by Vertex One Asset Management Inc. (“**Vertex**”), for aggregate gross proceeds of \$5.0 million. Each Vertex Unit consisted of one Common Share and one Warrant (each, a “**Vertex Warrant**”). Each Vertex Warrant entitled Vertex to purchase one Common Share at a price of \$0.10 per Common Share for five years from the closing date of the Vertex Offering (subject to early termination by the Corporation). The Vertex Warrants were voluntarily surrendered to the Corporation for cancellation on December 19, 2019 in connection with the Recapitalization Transaction. For more information, see “*Financial Year Ended December 31, 2019*”, above. Prior to closing the Vertex Offering, the Shareholders voted in favour of: (a) an ordinary resolution (the “**Control Person Resolution**”) to approve the Vertex Offering and VMVP becoming a new “Control Person” (as such term is defined in the policies of the TSXV) of the Corporation as a result of the Vertex Offering; and (b) an ordinary resolution authorizing Vertex Value Fund (“**VVF**”), another fund managed by Vertex, to exercise Warrants it purchased pursuant to the 2017 Offering (as defined below) that could have resulted in VVF becoming a “Control Person” of the Corporation if the Control Person Resolution had not passed. The Corporation also received disinterested Shareholder approval of the Control Person Resolution as required by Multilateral Instrument 61-101 – *Protection of Minority Security Holders in Special Transaction*.

Concurrently with the Vertex Offering, the Corporation issued 1,460,689 Common Shares on a flow-through basis at a price of \$0.10 per Common Share for aggregate gross proceeds of \$146,069.

On April 21, 2017, the Corporation acquired, through its wholly-owned subsidiary, Winslow, certain partner interests in its core area of Rycroft, north of Grande Prairie, Alberta, for cash consideration of \$715,000, effective February 1, 2017. The interests acquired included production of approximately 60 BOE/d (80% natural gas), and the remaining

50% non-operating interest in the Rycroft gathering system and gas plant, in which the Corporation bought its initial 50% operating interest in September 2016. In the second quarter of 2017, the Corporation further consolidated its interest in Rycroft by acquiring an additional 12 BOE/d from non-operated joint interest partners for total consideration of \$140,000. Return also added to its acreage position by purchasing five sections of prospective lands in the Rycroft area. The Corporation also disposed of certain non-core land and oil assets for gross proceeds of \$169,000 during the second quarter of 2017.

On April 1, 2017, Garry Hides was appointed as Executive Vice President of Return.

On March 14, 2017, Return completed a non-brokered private placement of 16,700,399 units (the “**2017 Offering Units**”) at a price of \$0.12 per 2017 Offering Unit and 715,000 Canadian exploration expense flow-through Common Shares (the “**Flow-Through Shares**”) at a price of \$0.14 per Flow-Through Share for gross proceeds of \$2,004,048 and \$100,000, respectively (collectively, the “**2017 Offering**”). Total gross proceeds from the 2017 Offering were \$2,104,148. Each 2017 Offering Unit consisted of one Common Share and one Warrant (each, a “**2017 Offering Warrant**”). Each 2017 Offering Warrant was exercisable into one Common Share at a price of \$0.15 for a period of one year from the issuance of such 2017 Offering Warrant. The 2017 Offering Warrants were subject to an accelerated warrant expiry upon the Corporation giving 30 days notice of early termination, which could be given if the volume-weighted average price of the Common Shares on the TSXV exceeded \$0.15 by at least 200% for a minimum of 10 consecutive trading days (whether or not trading of Common Shares occurs on all such days, provided that the Common Shares trade on at least five of such trading days). The Flow-Through Shares were issued pursuant to the Tax Act in respect of Canadian exploration expenses.

On January 5, 2017, the Corporation granted 2,070,000 Options to certain of its directors, officers, employees and consultants pursuant to the Corporation’s stock option plan. The Options had an exercise price of \$0.185 per Common Share, expired on January 5, 2022 and vested on a one-third basis on each of the first, second and third anniversaries of January 5, 2017. Such Options were voluntarily surrendered to the Corporation for cancellation on December 19, 2019 in connection with the Recapitalization Transaction. For more information, see “*Financial Year Ended December 31, 2019*”, above.

Significant Acquisition and Dispositions

During the fiscal year ended December 31, 2019, the Corporation did not complete any significant acquisitions as defined in NI 51-102.

NARRATIVE DESCRIPTION OF THE BUSINESS

General

Business Objectives and Strategy

Return is predominantly focused on opportunities in Alberta, growing through a targeted acquisition and consolidation strategy complemented by development and exploration drilling. The recapitalized corporate structure will allow for the exploitation of drilling locations targeting the Upper Charlie Lake at Rycroft and Lower Charlie Lake at Gordondale, and the expansion of Return’s opportunity suite through internally generated prospects and strategic acquisitions. The New Management Team is actively evaluating numerous acquisition opportunities, which have been materially enhanced by structural changes to the market over the last quarter, presenting opportunities to acquire top-tier assets at historically low valuations.

As part of its per share growth strategy, Return intends to focus on maintaining a clean balance sheet while targeting high quality assets with sustainable cash flow under current commodity prices. Return expects to acquire and develop underexploited, undercapitalized and distressed assets and corporations. In addition, Return intends to implement cost reduction strategies and focus on efficient capital allocation to enhance investor returns.

Return will selectively evaluate international opportunities to augment the recapitalized Corporation’s Canadian business plan. Return will target international assets with existing operations and meaningful conventional and

unconventional oil and gas resources in stable jurisdictions. Focusing on a base portfolio in Canada while augmenting its domestic operations with select international opportunities will allow Return to benefit from higher netbacks, global commodity price exposure and project diversification, providing Return with the flexibility to tailor the allocation of capital to different projects depending on the prevailing economic and political environments across various jurisdictions. In reviewing potential opportunities in markets outside of Canada, a number of factors will be considered, including: the scale of existing operations; sustainability of cash flow under current commodity prices; the proved producing, total proved and proved plus probable reserves; the potential for additional reservoir development; sufficient existing infrastructure to provide for scaled activity and product egress to market; the cost of any potential development; the ability to enhance the value of acquired properties through additional exploitation efforts and development drilling; and the political, fiscal and regulatory regimes in the region.

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

- target assets with sustainable cash flow and operations under current commodity prices;
- invest in highest tier inventory while generating free cash flow for acquisitions and dividends;
- look for high quality diversification opportunities in stable jurisdictions; and
- apply the highest standards of environment, sustainability and governance practices.

Specialized Skill and Knowledge

It is the belief of management of Return that Return's officers and employees, who have significant technical and operational oil and gas experience, hold the necessary skill sets to successfully execute Return's business strategy in order to achieve its corporate objectives. The New Management Team has an established track record of creating value across multiple business cycles in high-growth oil and gas companies through an integrated strategy of acquiring, exploiting and exploring assets.

Personnel

As at December 31, 2019, the Corporation did not have any full-time employees and Winslow had two contractors, whose services were being used on a regular basis for day-to-day operations. As of the date hereof, the Corporation has twelve full-time employees and one consultant, and Winslow has four contractors whose services are being used on a regular basis for day-to-day operations.

Industry Conditions

Recent Developments

To date in 2020, crude oil prices have declined dramatically, largely due to the actual and anticipated impact of the novel coronavirus ("COVID-19") outbreak upon global commerce and energy demand, and the recent disagreements between major oil producing nations with respect to production quotas. For more information, see "*Risk Factors – Commodity Price Volatility*" and "*Risk Factors – Public Health Crises*".

The OPEC production cuts in late 2019 and discussions of potentially further cuts in 2020 had, until recently, kept WTI oil prices in the mid-to-low US\$50s. On March 9, 2020, oil prices fell precipitously due primarily to disagreements between the major oil producing nations of Saudi Arabia and Russia and growing concerns regarding the COVID-19 outbreak, creating substantial uncertainty and volatility in the global energy markets. Since then, WTI has dropped as far as into the low US\$20s. In light of the current volatile environment, oil and gas producers may decrease their activities in general, both in the Canada and globally.

Until recently, overall global market conditions suggested that the industry would continue to maintain or increase production levels. Notwithstanding current uncertainties, Return remains committed to responding to market fundamentals and is carefully monitoring emerging developments.

Legislation and Regulation

The oil and natural gas industry is subject to extensive controls and regulations governing its operations (including land tenure, exploration, development, production, refining, transportation and marketing) imposed by legislation enacted by various levels of government and with respect to pricing and taxation of oil and natural gas by agreements among the governments of Canada and Alberta, all of which should be carefully considered by investors in the oil and natural gas industry. It is not expected that any of these controls or regulations will affect the operations of the Corporation in a manner materially different than they would affect other oil and natural gas producers 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. Some of the principal aspects of legislation, regulations and agreements governing the oil and natural gas industry are described further below.

Pricing and Marketing in Canada

Crude Oil

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

In February 2018, the federal government issued Bill C-69. Bill C-69 and related legislation came into force on August 28, 2019, creating a new regulatory regime pursuant to the CER Act, the *Canadian Navigable Waters Act* and the *Impact Assessment Act*. Bill C-69 does not materially alter the current requirements around oil exports; however, at this stage, it is not certain whether or when the federal government might issue new or revised regulations that might impact the oil export regime currently in place.

On December 2, 2018, the Government of Alberta announced that, commencing January 1, 2019, it would mandate an 8.7% short-term reduction in provincial crude oil and crude bitumen production. As contemplated in the Curtailment Rules, the Government of Alberta will, on a monthly basis, direct oil producers producing more than 10,000 Bbls/d to curtail their production according to a pre-determined formula that apportions production limits proportionately amongst those operators subject to a curtailment order. The first curtailment order took effect on January 1, 2019, limiting province-wide production of crude oil and crude bitumen to 3.56 million Bbls/d – a reduction of approximately 8.7% from the total daily average oil production in Alberta during December 2018. On August 20, 2019 the Government of Alberta announced that the curtailment end date will be December 31, 2020, with possible earlier termination and increased the base reduction from 10,000 Bbls/d to 20,000 Bbls/d. On October 28, 2019, the Government of Alberta announced a special production allowance whereby operators are allowed to produce above their curtailment order, as long as such extra production is shipped out of Alberta through additional rail capacity. Beginning December 1, 2019, and through at least April 2020, the production cap is a maximum output of 3.81 million Bbls/d.

Natural Gas

Alberta's natural gas market has been deregulated since 1985. Supply and demand determine the price of natural gas and price is calculated at the sale point, being the wellhead, the outlet of a gas processing plant, on a gas transmission system such as the Alberta "NIT" (Nova Inventory Transfer), at a storage facility, at the inlet to a utility system or at the point of receipt by the consumer. Accordingly, the price for natural gas is dependent upon such producer's own arrangements (whether long or short term contracts and the specific point of sale). As natural gas is also traded on trading platforms such as the Natural Gas Exchange (NGX), Intercontinental Exchange or the New York Mercantile Exchange (NYMEX) in the United States, spot and future prices can also be influenced by supply and demand fundamentals on these platforms.

The price of natural gas is determined by negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the CER and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the CER 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 cubic metres/day), must be made pursuant to an CER order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 40 years for natural gas and 25 years for NGLs) or for a larger quantity requires an exporter to obtain an export license from the CER subject to approval of the Governor in Council.

The Government of Alberta also regulates the volume of natural gas that may be removed from the province for consumption elsewhere based on such factors as reserve availability, transportation arrangements, and market considerations. Natural gas prices in Alberta have been constrained in recent years due to increasing supply in North America, limited access to markets and limited storage capacity.

Process for Exports from Canada

Crude oil, natural gas and NGLs exports from Canada are subject to the CER Act and the *National Energy Board Act Part VI (Oil and Gas) Regulation* (the “**Part VI Regulation**”) until these regulations are replaced under the CER Act. The CER Act and the Part VI Regulation authorize crude oil, natural gas and NGLs exports under either short-term orders or long-term licences.

To obtain a long-term crude oil export licence, a mandatory public hearing with the CER is required, which is no longer the case for natural gas and NGLs. For natural gas and NGLs, the CER uses a written process that includes a public comment period for impacted persons. Following the comment period, the CER completes its assessment of the application and either approves or denies the application. For natural gas, the maximum duration of an export licence is 40 years and, for crude oil and other gas substances (e.g. NGLs), the maximum term is 25 years. All crude oil, natural gas and NGLs licences require the approval of the cabinet of the Canadian federal government.

Orders from the CER provide a short-term alternative to export licences and may be issued more expediently, since they do not require a public hearing (in the case of crude oil) or approval from the cabinet of the Canadian federal government. Orders are issued pursuant to the Part VI Regulation for up to one or two years depending on the substance, with the exception of natural gas (other than NGLs) for which an order may be issued for up to twenty years for quantities not exceeding 30,000 m³ per day.

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

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

Transportation Constraints and Market Access

Alberta has seen significant growth in crude production volumes over recent years. This has resulted in pressure on the pipeline takeaway capacity, leading to apportionment on the main lines and, in turn, backed up local feeder pipelines. This has contributed to a widening of, and increased volatility in, the light oil pricing differential between West Texas Intermediate (“WTI”) and Canadian Light Sweet Edmonton and the medium/heavy oil pricing differential between WTI and Cromer/WCS/Hardisty/Edmonton. Although pipeline expansions are ongoing and producers are increasingly turning to rail as an alternative means of transportation, the lack of firm pipeline capacity continues to

affect the oil and natural gas industry and limit the ability to produce and to market production. In addition, the prorating of capacity on the interprovincial systems also continues to affect the ability to export oil and natural gas.

Under the Canadian Constitution, inter-provincial and international pipelines fall within the federal government's jurisdiction and require approval by both the CER and the cabinet of the federal government. On August 28, 2019, Bill C-69 and related legislation came into force, creating a new regulatory regime pursuant to the CER Act; the *Canadian Navigable Waters Act*; and the *Impact Assessment Act*. The CER Act replaced the NEB with the CER. The CER has similar oversight over federal energy infrastructure projects as the NEB had. However, approvals for projects requiring an impact assessment will now be conducted by a review panel established under the *Impact Assessment Act* instead of the CER. Its process for implementing this oversight are intended to be more inclusive of the Canadian public and Indigenous peoples and are to consider a broader range of impacts beyond environmental effects. Under the CER Act, if the review panel established under the *Impact Assessment Act* recommends that a project not be approved, the cabinet of the Canadian federal government may only reject the application or ask that the recommendation be reconsidered. As this regulatory regime is new, it is uncertain how it will play out in practice. Even when projects are approved on a federal level, such projects may face further delays due to interference by provincial and municipal governments as well as court challenges on various issues such as indigenous title, the government's duty to consult and accommodate indigenous peoples and the sufficiency of environmental review processes, which creates further uncertainty. Export pipelines from Canada to the United States face additional uncertainty as such pipelines also require approvals of several levels of government in the United States.

In the face of this regulatory uncertainty, the Canadian crude oil and natural gas industry has experienced significant difficulty expanding the existing network of transportation infrastructure for crude oil, natural gas and NGLs, including pipelines, rail, trucks and marine transport. Improved access to global markets, including the United States, and export shipping terminals on the west coast of Canada, could help to alleviate the downward pressures affecting commodity prices. Several proposals have been announced to increase pipeline capacity out of Alberta to reach Eastern Canada, the United States and international markets via export terminals. While certain projects are proceeding, the regulatory approval process and other economic and socio-political factors related to transportation and export infrastructure has led to the delay, suspension or cancellation of many pipeline projects.

The proposed Trans Mountain Pipeline expansion received Cabinet approval in November 2016. Following a period of sustained political opposition in British Columbia, the federal government entered into an agreement with Kinder Morgan Cochin ULC in May 2018 to purchase the shares and units of the entities that own and operate the Trans Mountain Pipeline system. The shareholders subsequently voted to approve the transaction in August 2018. However, in August 2018, the Federal Court of Appeal identified deficiencies in the NEB's environmental assessment of the Trans Mountain Pipeline expansion and the federal government's indigenous consultations. The Federal Court of Appeal quashed the accompanying certificate of public convenience and necessity and directed Cabinet to correct these deficiencies. Following the Federal Court of Appeal's direction, Cabinet ordered the NEB to reconsider its recommendation in light of the Federal Court of Appeal decision, including the environmental effects of project-related marine shipping. On February 22, 2019, the NEB delivered an updated report to Cabinet, recommending that Cabinet approve the pipeline expansion, subject to 156 conditions and 16 new recommendations, notwithstanding the fact that project-related marine shipping may have a significant adverse effect on the marine environment. On June 18, 2019, Cabinet approved the pipeline expansion, and on July 25, 2019, the NEB (now the CER) outlined how the regulatory process for the pipeline expansion would resume. On February 4, 2020, the Federal Court of Appeal dismissed legal challenges to the most recent approval of the project from six different parties. Construction on the pipeline expansion began in December 2019.

While it was expected that construction on the Keystone XL Pipeline would commence in the first half of 2019, preconstruction work was halted in late 2018 when a U.S. Federal Court Judge determined the underlying environmental review was inadequate. This decision has been appealed; however, in March 2019, a new permit was issued by the U.S. Government effectively lifting the injunction blocking construction. In August 2019, the Nebraska Supreme Court affirmed the approval of the Keystone XL Pipeline application and in October 2019, the State Department began soliciting comments on its draft environmental impact statement. On December 21, 2019, the same U.S. Federal Court Judge denied requests for a preliminary injunction in light of the U.S. Government's permit on the grounds that TC Energy, the owner of the pipeline, has voluntarily agreed to stop pre-construction activities until the second quarter of 2020. It is still uncertain when construction on the pipeline will begin.

Additionally, Bill C-48, the *Oil Tanker Moratorium Act* (the “**OTMA**”), came into force on June 21, 2019. The OTMA imposes a moratorium on tanker traffic transporting certain crude oil and NGLs products from British Columbia’s north coast. The OTMA is subject to a review after five (5) years.

The Government of Alberta sought to alleviate these transportation constraints by pursuing different transportation modalities and creating new markets. On November 28, 2018, the Government of Alberta announced that Alberta had started negotiations for investment in new rail capacity to address the historically high price differential. On February 19, 2019, the Government of Alberta announced that it would lease 4,400 rail cars capable of transporting 120,000 Bbls/d of crude oil out of the province; however, following the provincial election on April 16, 2019, the Government of Alberta announced it was in negotiations to transfer the rail car leases to the private sector, and announced on February 11, 2020 that it had transferred the rail car leases to the private sector.

On December 11, 2018, the Government of Alberta also announced a Request for Expressions of Interest to create new refining capacity or expand existing capacity. The deadline for interested parties to submit Expressions of Interest was February 8, 2019; however, this Request for Expression of Interest was discontinued on October 23, 2019 as the Government of Alberta announced a \$1.1 billion commitment to the Petrochemical Diversification Program which supports privately funded large-scale projects by providing royalty credits to companies that build facilities to turn ethane, methane and propane feedstocks into products such as plastics, fabrics and fertilizers.

Natural gas prices in Alberta have also been constrained in recent years due to increasing North American supply, limited access to markets and limited storage capacity. While companies that secure firm access to transport their natural gas production out of Alberta may be able to access more markets and obtain better pricing, other companies may be forced to accept spot pricing in Alberta for their natural gas, which in the last several years has generally been depressed (at times producers have received negative pricing for their natural gas production). Required repairs or upgrades to existing pipeline systems have also led to further reduced capacity and apportionment of firm access, which in Alberta may be further exacerbated by natural gas storage limitations. Additionally, while a number of LNG export plants have been proposed for the west coast of Canada, government decision-making, regulatory uncertainty, opposition from environmental and indigenous groups, and changing market conditions have resulted in the cancellation or delay of many of these projects. In October 2018, the proponents of the LNG Canada liquefied natural gas export terminal announced a positive final investment decision to proceed with the project.

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: (a) reduce the proportion of energy resources exported relative to domestic use (based upon the proportion prevailing in the most recent 36 month period); (b) impose an export price higher than the domestic price; or (c) 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.

On November 30, 2018, U.S. President Trump, Prime Minister Trudeau, and former Mexican President Enrique Peña Nieto signed an authorization for a new trade deal that will replace NAFTA, referred to as the USMCA. On December 10, 2019, the three countries formally agreed to the USMCA. However, NAFTA remains the North American trade agreement currently in force until the legislative bodies of the three signatory countries ratify the USMCA. Amid political uncertainty in Canada, Mexico, and the United States it is unclear when and if the USMCA will be ratified.

As the United States remains Canada’s largest trade partner and the largest international market for the export of crude oil, natural gas and NGLs from Canada, the implementation of the final ratified version of the USMCA could have an impact on Alberta’s crude oil and natural gas industry, including the Corporation’s business.

Other Trade Agreements

Canada and ten other countries recently concluded discussions and agreed on the draft text of the CPTPP, which is intended to allow for preferential market access among the countries that are parties to the CPTPP. On December 30, 2018 the CPTPP came into force for the first six countries to ratify the agreement: Canada, Australia, Japan, Mexico, New Zealand, and Singapore. On January 14, 2019, the CPTPP came into force for Vietnam.

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

While it is uncertain what effect CETA, CPTPP or any other trade agreements will have on the oil and gas industry in Canada, the lack of available infrastructure for the offshore export of oil and gas may limit the ability of Canadian oil and gas producers to benefit from such trade agreements.

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 \$100,000.00 per financial year. The categories of payments include taxes, royalties, fees, bonuses, dividends and infrastructure improvement payments. Payments to aboriginal governments are exempt from reporting obligations until 2017. Failure to comply with the reporting obligations under ESTMA are punishable upon summary conviction with a fine of up to \$250,000.00.

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 \$90.0 million in total liability.

Competition

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

Provincial Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations that govern land tenure, royalties, production rates, environmental protection and other matters. The royalty regime is a significant factor in the profitability of crude oil, natural gas, natural gas liquids and sulphur production. Royalties payable on production from lands other than Crown lands are determined by negotiations between the mineral owner and the lessee, although production from such lands is also subject to certain provincial taxes and royalties. Operations not on Crown lands and subject to the provisions of specific agreements are also usually subject to royalties negotiated between the mineral owner and the lessee. These royalties are not eligible for incentive programs sponsored by various governments as discussed below. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery and the type or

quality of the petroleum product produced. Other royalties and royalty-like interests are from time to time carved out of the working interest owner's interest through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests or net carried interests.

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

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

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 \$200.00 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 include 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 has also been 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 further 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. Any changes to the royalty regime in Alberta may have a material effect on the Corporation. See "*Risk Factors*".

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.

In July 2019, the Government of Alberta enacted the *Royalty Guarantee Act* which provides certainty that no major changes will be made to the current oil and gas royalty structure for a period of at least ten years.

Climate Change Regulation

Federal

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

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

Prior to the release of the Framework, the federal government announced in October 2016 that it will set a minimum price on carbon starting at \$10.00 per tonne of CO₂e in 2018, which will increase by \$10.00 per year until it reaches \$50.00 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 was 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 did not meet the federal minimum price, the federal government would 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.

In May 2017, Environment and Climate Change Canada (“ECCC”) released its Technical Paper on the Federal Carbon Pricing Backstop, which was followed by the *Guidance on the Pan-Canadian Carbon Pollution Pricing Benchmark* in August 2017. In December 2017, *Supplemental Benchmark Guidance* was issued and federal Environment Minister Catherine McKenna and Finance Minister Bill Morneau announced a deadline of September 1, 2018 for each province to outline how it is implementing a carbon pricing system that meets the federal standard. The federal government would then determine whether the planned systems are on track to meet the standard, or whether the federal approach should be applied in that jurisdiction. By the end of 2018, six (6) provinces had carbon pricing in place. Ontario cancelled its provincial cap-and-trade system in 2018 and in November of 2018 announced a new

climate plan that did not include a price on emissions. Alberta under its new United Conservative government has introduced a bill to repeal its provincial carbon tax (see “*Alberta*”, below). On January 15, 2018, ECCC released draft legislative proposals for public comment relating to the proposed *Greenhouse Gas Pollution Pricing Act* (the “**GGPPA**”) and the proposed regulatory framework for the output-based pricing system (which is designed to minimize competitiveness risks for emissions-intensive, trade-exposed industrial facilities). The comment periods for the federal carbon pricing backstop legislation and the regulatory framework ended on February 12, 2018 and April 9, 2018, respectively. The GGPPA came into force on June 21, 2018.

On May 27, 2017, the federal government published draft regulations to reduce emissions of methane from the crude oil and natural gas sector. The proposed regulations aim to reduce unintentional leaks and intentional venting of methane, as well as ensuring that crude oil and natural gas operations use low-emission equipment and processes, by introducing new control measures. Among other things, the proposed regulations limit how much methane upstream oil and gas facilities are permitted to vent. These facilities would need to capture the gas and either re-use it, re-inject it, send it to a sales pipeline, or route it to a flare. In addition, in provinces other than Alberta and British Columbia (which already regulate such activities), well completions by hydraulic fracturing would be required to conserve or destroy gas instead of venting. The *Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds* came into effect on April 26, 2018. The federal government anticipates that these actions will reduce annual GHG emissions by about 20 megatonnes by 2030.

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

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

In November 2016, the federal government announced that it would commence development of a performance-based clean fuel standard (“**CFS**”) that would incent the use of a broad range of low carbon fuels, energy sources and technologies. The objective of the CFS is to achieve 30 Mt of annual reductions in GHG emissions by 2030, as part of efforts to achieve Canada’s commitments under the Paris Agreement. On December 13, 2017, ECCC published a regulatory framework on the CFS, which outlines the key design elements for the CFS regulation, including its scope, regulated parties, carbon intensity approach, timing, and potential compliance options such as credit trading. Draft CFS regulations are expected to be published in early 2020.

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

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 to reduce their GHG emissions intensity by 12% (from average 2003-2005 levels). On June 25, 2015,

the Government of Alberta renewed the SGER for a period of two years with significant amendments while Alberta's Climate Advisory Panel conducted a comprehensive review of the province's climate change policy.

Alberta's Climate Leadership Plan was introduced in November 2015 with the following policy objectives: (a) putting a price on GHG emissions; (b) phasing out coal-generated electricity by 2030; (c) having 30% of electricity be generated from renewable sources by 2030; (d) capping oil sands emissions to 100 Mt per year; and (e) reducing methane emissions by 45% by 2025. On May 30, 2019 the Climate Leadership Plan was abolished in the *Carbon Tax Repeal Act*.

Carbon pricing was identified under the Climate Leadership Plan as a key policy tool for reducing GHG emissions. On January 1, 2017, a carbon levy of \$20.00 per tonne of CO₂e was implemented and applies to all heating and transportation fuels. The carbon levy increased to \$30.00 per tonne on January 1, 2018.

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

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

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

In January 2018, the Alberta government also announced that it is adopting ECCC's greenhouse gas reporting requirements for the 2017 reporting period, meaning that facilities emitting 10,000 tonnes of CO₂e or more must submit a specified gas report to Alberta Climate Change Office via ECCC's SWIM reporting system (the reporting threshold for previous years is 50,000 tonnes of CO₂e). Facilities must report their 2017 greenhouse gas emissions to ECCC's SWIM system by June 1, 2018.

On October 29, 2019, the Government of Alberta announced Bill 19 to replace the CCI Regulation with the *Technology Innovation and Emissions Reduction* ("**TIER**"). Under TIER, thresholds for large facilities and compliance mechanisms remain largely the same as under the CCI Regulation. However, under TIER, a facility will be measured either against its own average emissions from prior years and its target will be set at ten percent below that level for 2020, or using an industry specific benchmark set by regulation. If a facility is over its target, the price will be \$30.00 per tonne CO₂e.

Beginning on May 30, 2019 as part of the *Carbon Tax Repeal Act*, the carbon levy no longer applies to any type of fuel; however, as Alberta has no carbon levy equivalent for fuel consumption, the federal government announced that beginning on January 1, 2020 a federal fuel charge will apply in Alberta.

Land Tenure

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

The Government of Alberta predominantly owns the rights to crude oil and natural gas within the province. The Government of Alberta grant rights to explore for and produce oil and natural gas pursuant to leases, licences and permits for varying terms and on conditions set forth in provincial legislation, including requirements to perform specific work or make payments. Private ownership of oil and natural gas also exists in Alberta 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.

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

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

Environmental Regulation

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.

Federal

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

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

On August 28, 2019, the Government of Canada enacted new legislation to overhaul the existing environmental assessment process and replace the NEB with the CER. Pursuant to the legislation, the Impact Assessment Agency of Canada (the “**Agency**”) would replace the Canadian Environmental Assessment Agency. Additional categories of projects are included within new impact assessment process, such as offshore wind energy projects; however, exemptions have been added for oil sands projects located in provinces that have achieved requisite greenhouse gas emissions targets. The revamped approval process for applicable major developments has specific legislated timelines at each stage of the formal impact assessment process. The Agency’s process would focus on: (a) early engagement by proponents to engage the Agency and all stakeholders, such as the public and indigenous groups, prior to the formal impact assessment process; (b) potentially increased public participation where the project undergoes a panel review; (c) providing analysis of the potential impacts and effects of a project without making recommendations, to support a public-interest approach to decision-making, with cost-benefit determinations and approvals made by the Minister of Environment and Climate Change or the cabinet of the federal government; (d) analyzing further specified factors for projects such as alternatives to the project and social and indigenous issues in addition to health, environmental and economic impacts; and (e) overseeing an expanded follow-up, monitoring and enforcement process with increased involvement of indigenous peoples and communities. Many of the CER’s activities are now similar to the NEB, but with a different structure and the notable exception that the CER would no longer have primary responsibility in the consideration of the new major projects, instead focusing on the lifecycle regulation (e.g. overseeing construction, tolls and tariffs, operations and eventual winding down) of approved projects, while providing for expanded participation by communities and indigenous peoples. The effects of the new legislation remain unclear as the old NEB regulations are still in force until such new regulations come into force.

On May 12, 2017, the federal government introduced the *Oil Tanker Moratorium Act* (“**OTMA**”) in Parliament. This legislation is aimed at providing coastal protection in northern British Columbia by prohibiting crude oil tankers carrying more than 12,500 metric tonnes of crude oil or persistent crude oil products from stopping, loading, or unloading crude oil in that area. The OTMA came into force on June 21, 2019 and may prevent the building of pipelines to, and export terminals located on, the portion of the British Columbia coast subject to the moratorium and, as a result, negatively affect the ability of producers to access global markets.

Alberta

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 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.

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.

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

In Alberta, the AER 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 well fund (the "**Orphan Well 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 becomes defunct. The Orphan Well 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 Well 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 a three-year 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.

On June 20, 2016, the AER issued Bulletin 2016-16, Licensee Eligibility – Alberta Energy Regulator Measures to Limit Environmental Impacts Pending Regulatory Changes to Address the Redwater Decision ("**Bulletin 16**") in an urgent response to a decision from the Alberta Court of Queen's Bench, which was affirmed by a majority at the Alberta Court of Appeal. In *Redwater Energy Corporation (Re)*, 2016 ABQB 278 ("**Redwater**"), Chief Justice Wittman found that there was an operational conflict between the abandonment and reclamation provisions of the OGCA and the *Bankruptcy and Insolvency Act* ("**BIA**"), and that receivers and trustees had the right to renounce assets within insolvency proceedings. Such a conflict rendered the AER's legislated authority unenforceable to impose abandonment orders against licensees or to require a licensee to pay a security deposit before approving a transfer when such a licensee is insolvent. Effectively, this meant that abandonment costs would be borne by the industry-

funded Orphan Well Fund or the province in these instances because any resources of the insolvent licensee would first be used to satisfy secured creditors under the BIA.

Bulletin 16 provided interim rules to govern while the case was appealed and while the Government of Alberta can develop appropriate regulatory measures to adequately address environmental liabilities. The AER's Directive 067: Applying for Approval to Hold EUB Licences ("**Directive 067**") was amended and now requires extensive corporate governance and shareholder information, with a focus on any previous insolvency proceedings in order to acquire or transfer licenses needed to operate wells and facilities. The AER will consider and process all applications for licence eligibility under Directive 067 as non-routine and may exercise its discretion to refuse an application or impose terms and conditions on a licensee eligibility approval if appropriate in the circumstances. As a condition of transferring existing AER licences, approvals, and permits, the AER will require all transferees to demonstrate that they have a liability management rating, being the ratio of a licensee's assets to liabilities, of 2.0 or higher immediately following the transfer.

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. The objective is to bring all inactive noncompliant wells under the IWCP into compliance with the requirements of Directive 013 within five years. As of April 1, 2015, each licensee is required to bring 20 percent of its inactive wells into compliance every year, either by reactivating or suspending the wells in accordance with Directive 013 or by abandoning them in accordance with Directive 020: Well Abandonment. The list of current wells subject to the IWCP is available on the AER's Digital Data Submission system. The AER has announced that from April 1, 2015 to April 1, 2016, the number of noncompliant wells subject to the IWCP fell from 25,792 to 17,470, with 76 percent of licensees operating in the province having met their annual quota. The IWCP completed its second year on March 31, 2017. Overall, the AER has announced that licensees brought 19 percent of non-compliant wells in the IWCP into compliance with AER requirements in the second year of the IWCP.

On January 31, 2019, the Supreme Court of Canada ("**SCC**") ruled on the appeal of Redwater in *Orphan Well Association v. Grant Thornton Limited*, 2019 SCC 5, in favour of the AER and Orphan Well Association. Specifically, the SCC held that while trustees will not be personally liable for abandonment and reclamation obligations, the estate will remain liable for such obligations. As a result, reclamation and abandonment liabilities must be dealt with before there can be any distribution to the insolvent parties' creditors, including its secured creditors. In response to the SCC's decision, the AER is working on an improved liability management framework. Return cannot predict what the AER's improved framework may look like but such pending changes to the Alberta LLR Program will have an impact on crude oil and natural gas production in Alberta, including Return's business.

Social or Environmental Policies

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

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

Return believes that all employees have a vital role in achieving excellence in environmental, health and safety performance, which is best achieved through careful planning and the support and active participation of everyone involved. Furthermore, the Corporation aligns itself with the best industry practices to ensure positive results.

RISK FACTORS

Return's business consists of the exploration for and development and production of petroleum and natural gas properties in the Western Canadian Sedimentary Basin. The Corporation is currently focused on the Peace River Arch area in northwest Alberta. There are a number of inherent risks associated with the exploration for and development and production of petroleum and natural gas. Many of these risks are beyond the control of the Corporation. Investors should carefully consider the risk factors set out below and consider all other information contained herein and in the Corporation's other public filings before making an investment decision.

Stage of Development

An investment in Return is subject to certain risks related to the nature of Return's business and its stage of development. There are numerous factors which may affect the success of Return's business which are beyond Return's control including local, national and international economic and political conditions. Return's business involves a high degree of risk which a combination of experience, knowledge and careful evaluation may not overcome. There can be no assurance that Return's business will be successful or profitable.

Difficulty Implementing Business Strategy

The growth and expansion of the Corporation is heavily dependent upon the successful implementation of its business strategy. There can be no assurance that the Corporation will be successful in the implementation of its business strategy.

Commodity Price Volatility

Return's results of operations and financial condition are dependent on the prevailing prices of crude oil and natural gas. Crude oil and natural gas prices have fluctuated widely in the recent past and are subject to fluctuations in response to relatively minor changes in supply, demand, market uncertainty and other factors that are beyond Return's control.

Crude oil and natural gas prices are impacted by a number of factors including, but not limited to: the global supply of and demand for crude oil and natural gas; global economic conditions; the actions of OPEC and OPEC+; government regulation; political stability; the ability to transport crude to markets; developments related to the market for liquefied natural gas; the availability and prices of alternate fuel sources; and weather conditions. Recently, global oil prices have weakened materially as a result of the COVID-19 pandemic, compounded by OPEC+, led by Saudi Arabia and Russia, failing to reach an agreement on constraining output. Concerns over global economic conditions, fluctuations in interest rates and foreign exchange rates, stock market volatility, energy costs, geopolitical issues, OPEC+ actions, inflation, the availability and cost of credit, the deceleration of economic growth in the People's Republic of China, trade disputes between the United States and the People's Republic of China, civil unrest in Venezuela and Iran and the outbreak of COVID-19 have contributed to increased economic uncertainty and diminished expectations for the global economy. In addition, significant growth in crude production volumes in western Canada and the northern United States has resulted in pressure on transportation and pipeline capacity, contributing to the widening of the light oil pricing differential between WTI and Cromer/WCS/Hardisty, resulting in fluctuations in the price of oil and natural gas. All of these factors are beyond Return's control and can result in a high degree of price volatility.

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

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

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

Crude oil and natural gas prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and the demand of these commodities due to the current state of the world economies, OPEC+ actions and the current COVID-19 pandemic. Volatile oil and gas prices make it difficult to estimate the value of producing properties for acquisition and often cause disruption in the market for oil and gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects.

In addition, bank borrowings available to the Corporation may, in part, be determined by the Corporation's borrowing base. A sustained material decline in prices from historical average prices could reduce the Corporation's borrowing base, therefore reducing the bank credit available to the Corporation which could require that a portion, or all, of the Corporation's bank debt be repaid.

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

Public Health Crises

Return's business, operations and financial condition could be materially adversely affected by the outbreak of epidemics or pandemics or other health crises. In December 2019, COVID-19 was reported to have surfaced in Wuhan, China. On January 30, 2020, the World Health Organization declared the outbreak a global health emergency and on March 11, 2020, the World Health Organization declared the outbreak a pandemic. In China, reactions to the spread of COVID-19 have led to, among other things, significant restrictions on travel within China, temporary business closures, quarantines and a general reduction in consumer activity. The outbreak has spread throughout Europe, the Middle East, Canada and the United States, causing companies and various international jurisdictions to impose restrictions such as quarantines, business closures, restrictions on public gatherings and travel restrictions. While these effects are expected to be temporary, the duration of the business disruptions internationally and related financial impact cannot be reasonably estimated at this time. Similarly, Return cannot estimate whether, or to what extent, this outbreak and the potential financial impact may extend to countries outside of those currently impacted.

Such public health crises can result in volatility and disruptions in the supply and demand for oil and natural gas, global supply chains and financial markets, as well as declining trade and market sentiment and reduced mobility of people, all of which could affect commodity prices, interest rates, credit ratings, credit risk and inflation. In particular, oil prices have significantly weakened in response to the outbreak of COVID-19. See "*Commodity Price Volatility*", above. The risks to Return of such public health crises also include risks to employee health and safety and a slowdown or temporary suspension of operations in geographic locations impacted by an outbreak. At this point, the extent to which COVID-19 may impact Return is uncertain; however, it is possible that COVID-19 may have a material adverse effect on the Return's business, results of operations and financial condition.

Gathering and Processing Facilities, Pipeline Systems and Rail

The Corporation primarily delivers its products through gathering and processing facilities and pipeline systems, some of which it does not own. The amount of oil and natural gas that the Corporation can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering and processing facilities, pipeline systems and railway lines. The lack of availability of capacity in any of the gathering and processing facilities, pipeline systems and railway lines could result in the inability to realize the full economic potential of the Corporation's production or in a reduction of the price offered for its production. The lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to transport produced oil and gas to market. In addition, the pro-rationing of capacity on inter-provincial pipeline systems continues to affect the ability to export oil and natural gas. Unexpected shut downs or curtailment of capacity of pipelines for maintenance or integrity work or because of actions taken by regulators could also affect the Corporation's production, operations and financial results. As a result, producers are increasingly turning to rail as an alternative means of transportation. In recent years, the volume of crude oil shipped by rail in North America has increased dramatically. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays or uncertainty in constructing new infrastructure systems and facilities could harm the Corporation's business and, in turn, its financial condition, operations and cash flows. Announcements and actions taken by the government of Alberta relating to approval of infrastructure projects may continue to intensify, leading to increased challenges to interprovincial and international infrastructure projects moving forward. In addition, while the federal government recently passed Bill C-69 to overhaul the existing environmental assessment process and replacing the NEB with the CER, the impact of the new regulatory scheme on proponents and the timing of receipt of approvals of major projects remains unclear.

A portion of Return's production may, from time to time, be processed through facilities owned by third parties and over which Return does not have control. From time to time, these facilities may discontinue or decrease operations either as a result of normal servicing requirements or as a result of unexpected events. A discontinuance or decrease of operations could have a materially adverse effect on Return's ability to process its production and deliver the same for sale. Midstream and pipeline companies may take actions to maximize their return on investment which may in turn adversely affect producers and shippers, especially when combined with a regulatory framework that may not always align with the interests of particular shippers.

Capital Lending Markets

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

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

Markets and Marketing

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

Exploration, Development and Production Risks

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

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

Weakness in the Oil and Gas Industry

Recent market events and conditions, including global excess oil and natural gas supply, actions taken by OPEC+, the COVID-19 pandemic, slowing growth in emerging economies, market volatility and disruptions in Asia, sovereign debt levels and political upheavals in various countries have caused significant weakness and volatility in commodity prices. These events and conditions have caused a significant decrease in the valuation of oil and gas companies and a decrease in confidence in the oil and gas industry. These difficulties have been exacerbated in Canada by political and other actions resulting in uncertainty surrounding regulatory, tax, royalty changes and environmental regulation. In addition, the inability to get the necessary approvals to build pipelines, LNG plants and other facilities to provide better access to markets for the oil and gas industry in Alberta has led to additional downward price pressure on oil and gas produced in Alberta and uncertainty and reduced confidence in the oil and gas industry in Alberta. Lower commodity prices may also affect the volume and value of the Corporation's reserves, rendering certain reserves uneconomic. In addition, lower commodity prices have restricted, and may continue to restrict, the Corporation's cash flow resulting in a reduced capital expenditure budget. Consequently, the Corporation may not be able to replace its production with additional reserves and both the Corporation's production and reserves could be reduced on a year over year basis.

Political Uncertainty

In the last several years, the United States and certain European countries have experienced significant political events that have cast uncertainty on global financial and economic markets. Since the 2016 U.S. presidential election, the U.S. has withdrawn from the CPTPP and Congress has passed sweeping tax reform, which, among other things, significantly reduces U.S. corporate tax rates. This may affect competitiveness of other jurisdictions, including Canada. In addition, NAFTA has been renegotiated and on December 10, 2019, Canada, the U.S. and Mexico signed the USMCA, which has subsequently been ratified by each country. See “*Narrative Description of the Business – Industry Conditions – The North American Free Trade Agreement*”. The U.S. administration has also taken action with respect to reduction of regulation, which may also affect relative competitiveness of other jurisdictions. It is presently unclear how these actions may impact Canada and in particular the oil and gas industry. Any actions taken by the United States administration may have a negative impact on the Canadian economy and on the businesses, financial conditions, results of operations and the valuation of Canadian oil and gas companies, including Return.

In addition to the political disruption in the United States, the citizens of the United Kingdom have voted to withdraw from the European Union and the Government of the United Kingdom implemented such withdrawal on January 31, 2020. Some European countries have also experienced the rise of anti-establishment political parties and public protests held against open door immigration policies, trade and globalization. To the extent that certain political actions taken in North America, Europe and elsewhere in the world result in a marked decrease in free trade, access to personnel and freedom of movement, it could have an adverse effect on Return’s ability to market products internationally, increase costs for goods and services required for operations, reduce access to skilled labour and negatively impact business, operations, financial conditions and the market value of the Common Shares.

Substantial Capital Requirements

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

Additional Funding Requirements

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

Future Sales of Common Shares

Return may issue additional Common Shares in the future to pursue its business strategy, which may dilute a Shareholder’s holdings in the Corporation. Return’s articles permit the issuance of an unlimited number of Common Shares and Shareholders will have no pre-emptive rights in connection with such further issuances. Also, additional

Common Shares may be issued by the Corporation on the exercise of Warrants or on the exercise of Options under the Corporation's stock option plan.

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

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

Operational Dependence

Other companies operate some of the assets in which the Corporation has an interest. As a result, the Corporation has limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect the Corporation's financial performance. The Corporation's return on assets operated by others therefore depends upon a number of factors that may be outside of the Corporation's control, including the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

Project Risks

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

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

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

Competition

The petroleum industry is competitive in all its phases. Return competes with numerous other organizations in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas. Return's competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than those of the Corporation. Return's ability to increase its reserves in the future will depend not only on its ability

to explore and develop its present properties, but also on its ability to select and acquire other suitable producing properties or prospects for exploratory drilling. Competitive factors in the distribution and marketing of oil and natural gas include price and methods and reliability of delivery and storage. Competition may also be presented by alternate fuel sources.

Cost of New Technologies

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

Regulatory

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

Fiscal and Royalty Regime

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

Environmental

All phases of the oil and gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and natural gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Corporation to incur costs to remedy such discharge. Although the Corporation believes that it will be in material compliance with current applicable environmental regulations, no assurance can be given that environmental laws will not result in a curtailment of

production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

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

Climate Change

Return's exploration and production facilities and other operations and activities emit GHGs and which may require Return 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 ultimately put in place. Public support for climate change action and receptivity to new technologies has grown in recent years. Governments in Canada and around the world have responded to these shifting societal attitudes by adopting ambitious emissions reduction targets and supporting legislation, including measures relating to carbon pricing, clean energy and fuel standards, and alternative energy incentives and mandates. There has also been increased activism, including threats of culpability, legal action against oil and gas producers, and public opposition to fossil fuels and the oil and gas industry in which the Corporation operates. Given the evolving nature of the debate related to climate change and the control of GHGs and resulting requirements, it is not possible to predict the impact on Return and its operations and financial condition. See *"Narrative Description of the Business – Industry Conditions – Climate Change Regulation"*.

Variations in Foreign Exchange Rates and Interest Rates

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

Issuance of Debt

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

Hedging

From time to time the Corporation may enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline; however, if commodity prices increase beyond the levels set in such agreements, the Corporation will not benefit from such increases and the Corporation may nevertheless be obligated to pay royalties on such higher prices, even though not received by it, after giving effect to such agreements. Similarly, from time to time the Corporation may enter into agreements to fix the exchange rate

of Canadian to U.S. dollars in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the U.S. dollar; however, if the Canadian dollar declines in value compared to the U.S. dollar, the Corporation will not benefit from the fluctuating exchange rate.

Availability of Drilling Equipment and Access

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment (typically leased from third parties) in the particular areas where such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to the Corporation and may delay exploration and development activities.

Title to Assets

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

Reserve Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and natural gas liquids reserves and the future cash flows attributed to such reserves.

The reserve and associated cash flow information set forth herein are estimates only. In general, estimates of economically recoverable oil and natural gas reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially from actual results. For those reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times, may vary. Return's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material. Further, the evaluations are based in part on the assumed success of exploitation activities intended to be undertaken in future years. The reserves and estimated cash flows to be derived therefrom contained in such evaluations will be reduced to the extent that such exploitation activities do not achieve the level of success assumed in the evaluation.

Estimates of proved reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Recovery factors and drainage areas were estimated by experience and analogy to similar producing pools.

Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history and production practices will result in variations in the estimated reserves and such variations could be material.

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

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

In accordance with applicable securities laws, the Corporation's independent reserves evaluator has used forecast prices and costs in estimating the reserves and future net cash flows as summarized herein. Actual future net cash flows will be affected by other factors, such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs.

Insurance

Return's involvement in the exploration for and development of oil and natural gas properties may result in the Corporation becoming subject to liability for pollution, blow outs, leaks of sour natural gas, property damage, personal injury or other hazards. Although the Corporation maintains insurance in accordance with industry standards to address certain of these risks, such insurance has limitations on liability and may not be sufficient to cover the full extent of such liabilities. In addition, such risks are not, in all circumstances, insurable or, in certain circumstances, the Corporation may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of any uninsured liabilities would reduce the funds available to the Corporation. The occurrence of a significant event that the Corporation is not fully insured against, or the insolvency of the insurer of such event, may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Geo-Political Risks

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

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

Management of Growth

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

Expiration of Licences and Leases

Return's properties are held in the form of licences and leases and working interests in licences and leases. If the Corporation or the holder of the licence or lease fails to meet the specific requirement of a licence or lease, the licence or lease may be suspended, terminated or it may expire. There can be no assurance that any of the obligations required to maintain each licence or lease will be met. The termination or expiration of the Corporation's licences or leases or the working interests relating to a licence or lease may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Litigation

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

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights to portions of Alberta. Return is not aware that any claims have been made in respect of its properties and assets; however, if a claim arose and was successful such claim may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Dividends

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

Breach of Confidentiality

While discussing potential business relationships or other transactions with third parties, the Corporation may disclose confidential information relating to the business, operations or affairs of this Corporation. Although confidentiality agreements are signed by third parties prior to the disclosure of any confidential information, a breach could put the Corporation at competitive risk and may cause significant damage to its business. The harm to the Corporation's business from a breach of confidentiality cannot presently be quantified, but may be material and may not be compensable in damages. There is no assurance that, in the event of a breach of confidentiality, the Corporation will be able to obtain equitable remedies, such as injunctive relief, from a court of competent jurisdiction in a timely manner, if at all, in order to prevent or mitigate any damage to its business that such a breach of confidentiality may cause.

Seasonality and Extreme Weather Conditions

The level of activity in the Canadian oil and gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Roads bans and other restrictions generally result in a reduction of drilling and exploratory activities and may also result in the shut-in of some of the Corporation's production if not otherwise tied-in. Also, certain oil and gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. In addition, extreme cold weather, heavy snowfall and heavy rainfall may restrict Return's ability to access its properties, cause operational difficulties including damage to machinery or contribute to personnel injury because of dangerous working conditions. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and corresponding declines in the demand for the goods and services of the Corporation.

Third Party Credit Risk

Return may be exposed to third party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production and other parties. In the event such entities fail to meet their contractual obligations to the Corporation, such failures may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In addition, poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in the

Corporation's ongoing capital program, potentially delaying the program and the results of such program until the Corporation finds a suitable alternative partner.

Conflicts of Interest

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

Reliance on Key Personnel

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

Expansion into New Activities

The operations and expertise of the Corporation's management are currently focused primarily on oil and gas production, exploration and development in Alberta. In the future the Corporation may acquire or move into new industry related activities or new geographical areas, may acquire different energy related assets, and as a result may face unexpected risks or alternatively, significantly increase the Corporation's exposure to one or more existing risk factors, which may in turn result in the Corporation's future operational and financial conditions being adversely affected.

Alternatives to and Changing Demand for Petroleum Products

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas, and technological advances in fuel economy and renewable energy generation devices could reduce the demand for crude oil and liquid hydrocarbons. Recently, certain jurisdictions have implemented policies or incentives to decrease the use of fossil fuels and encourage the use of renewable fuel alternatives, which may lessen the demand for petroleum products and put downward pressure on commodity prices. In addition, advancements in energy efficient products have a similar effect on the demand for oil and gas products. Return cannot predict the impact of changing demand for oil and natural gas products, and any major changes may have a material adverse effect on the Corporation's business, financial condition, results of operations and cash flows.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

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

Hydraulic Fracturing

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

Waterflood

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

Liability Management

Alberta has developed liability management programs designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licensee or permit holder becomes defunct. 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 the Corporation must post.

As a result of the Supreme Court of Canada's January 2019 decision in the Redwater case, a trustee in bankruptcy is not permitted to renounce uneconomic oil and gas assets and leave these assets to be remediated by the Orphan Well Fund, thereby avoiding the environmental liabilities of the estate it is administering. Accordingly, the AER may now use Alberta's provincial legislative scheme to prevent the repudiation or renunciation of an insolvent company's assets by a trustee and require the trustee to satisfy certain environmental obligations in priority to the claims of secured and unsecured creditors. In response to the Supreme Court's decision, the AER is also working on an improved liability management framework. Return cannot predict what the AER's improved framework may look like but such pending changes to the Alberta LLR Program will have an impact on crude oil and natural gas production in Alberta, including Return's business.

The AER's new liability management framework may impact the Corporation's ability to transfer its licences, approvals or permits in the course of a divestment, and may result in increased costs and delays or require changes to or abandonment of projects and transactions. As a result of the decision in Redwater, lenders may reduce the availability of credit to oil and gas issuers that utilize secured loans, thereby negatively affecting the financial capacity of such issuers, including potential partners and counterparties of the Corporation. Lenders also may generally increase their scrutiny of oil and gas assets held by producers, including the Corporation, and the associated abandonment and reclamation liabilities in determining whether to provide credit, may require borrowers to adhere to more stringent abandonment and reclamation-related operational covenants, and may increase the cost of providing credit.

The Supreme Court decision in Redwater also could make the transfer of oil and gas assets from insolvent parties more challenging if a trustee in bankruptcy is unable to separate economic assets from uneconomic assets within the insolvent party's estate in order to facilitate a sale process. The result could be additional liabilities being placed upon the Orphan Well Fund. The Orphan Well Fund may seek funding for such liabilities from industry participants, including the Corporation, through an increase in its annual levy, further changes to regulations, or other means. While the impact on the Corporation of any legislative, regulatory or policy decisions as a result of the Redwater decision cannot be reliably or accurately estimated, any cost recovery or other measures taken by applicable regulatory bodies

may impact the Corporation and materially and adversely affect, among other things, the Corporation's business, financial condition, results of operations and cash flow.

There remains a great deal of uncertainty as to what new regulatory measures will be developed by the provinces or in concert with the federal government, as the final ruling will become binding in all Canadian jurisdictions. See *"Narrative Description of the Business – Industry Conditions – Liability Management Rating Programs"*.

Information Technology Systems and Cyber-Security

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

Further, Return is subject to a variety of information technology and system risks as a part of its normal course operations, including potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach, and destruction or interruption of its information technology systems by third parties or insiders. Unauthorized access to these systems by employees or third parties could lead to corruption or exposure of confidential, fiduciary or proprietary information, interruption to communications or operations or disruption to its business activities or its competitive position. In addition, cyber phishing attempts, in which a malicious party attempts to obtain sensitive information such as usernames, passwords, and credit card details (and money) by disguising as a trustworthy entity in an electronic communication, have become more widespread and sophisticated in recent years. If Return becomes a victim to a cyber phishing attack it could result in a loss or theft of the Corporation's financial resources or critical data and information or could result in a loss of control of its technological infrastructure or financial resources. Return applies technical and process controls in line with industry-accepted standards to protect its information assets and systems; however, these controls may not adequately prevent cyber-security breaches. Disruption of critical information technology services, or breaches of information security, could have a negative effect on Return's performance and earnings, as well as on its reputation. The significance of any such event is difficult to quantify, but may in certain circumstances be material and could have a material adverse effect on its business, financial condition and results of operations.

Disposal of Fluids Used in Operations

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

Carbon Pricing Risk

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

Reputational Risk Associated with Operations

Any environmental damage, loss of life, injury or damage to property caused by Return's operations could damage its reputation in the areas in which the Corporation operates. Negative sentiment towards Return could result in a lack of

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

Changing Investor Sentiment

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

Forward-Looking Information May Prove to be Inaccurate

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

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

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Reserves Categories

Types of Reported Reserves

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

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

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

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

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

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

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

- (a) Developed reserves are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.
 - (i) Developed producing reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.
 - (ii) Developed non-producing reserves are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.
- (b) Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable) to which they are assigned.

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

Levels of Certainty for Reported Reserves

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

- (a) at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and
- (b) at least a 50 percent probability that the quantities actually recovered will equal or exceed the estimated proved plus probable reserves.

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

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

Interests in Reserves, Production, Wells and Properties

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

- (a) **"gross"** means: (i) in relation to an issuer's interest in production or reserves, its "company gross reserves", which are its working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests of the issuer; (ii) in relation to wells, the total number of wells in which an issuer has an interest; and (iii) in relation to properties, the total area of properties in which an issuer has an interest.
- (b) **"net"** means: (i) in relation to an issuer's interest in production or reserves its working interest (operating or non-operating) share after deduction of royalty obligations, plus its royalty interests in production or reserves; (ii) in relation to an issuer's interest in wells, the number of wells obtained by aggregating the issuer's working interest in each of its gross wells; and (iii) in relation to an issuer's interest in a property, the total area in which the issuer has an interest multiplied by the working interest owned by the issuer.
- (c) **"working interest"** means the percentage of undivided interest held by an issuer in the oil and/or natural gas or mineral lease granted by the mineral owner, Crown or freehold, which interest gives the issuer the right to "work" the property (lease) to explore for, develop, produce and market the leased substances.

Description of Exploration and Development Wells and Costs

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

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

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

"exploration well" means a well that is not a development well, a service well or a stratigraphic test well; and

“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.

Reserves Data (Forecast Prices and Costs)

The reserves data set forth below (the “Reserves Data”) is based upon a report prepared by Sproule, independent petroleum consultants, evaluating the light and medium oil, conventional natural gas and natural gas liquids reserves of Return, as at December 31, 2019, dated March 31, 2020 (the “Sproule Report”). The Reserves Data summarizes the light and medium oil, conventional natural gas and natural gas liquids of the Corporation and the net present values of future net revenue for these reserves using forecast prices and costs. The Sproule Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101 and the COGE Handbook. Additional information not required by NI 51-101 has been presented to provide continuity and additional information which Return believes is important to the readers of this information. The Corporation engaged Sproule to provide an evaluation of proved and proved plus probable reserves and no attempt was made to evaluate possible reserves.

The net present value of future net revenue attributable to the Corporation’s reserves is stated without provision for interest costs and general and administrative costs, but after providing for estimated royalties, production costs, development costs, other income, future capital expenditures, and well abandonment costs for only wells on active properties. It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. The recovery and reserve estimates of the Corporation’s light and medium oil, solution and natural gas and natural gas liquids provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual light and medium oil, solution and natural gas and natural gas liquids reserves may be greater than or less than the estimates provided herein. For more information, see “Risk Factors – Reserve Estimates”, below. Readers should note that the totals in the following tables may not add due to rounding.

All properties evaluated are located in the Provinces of Alberta. All monetary values are expressed in Canadian dollars, unless stated otherwise.

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

Summary of Oil and Natural Gas Reserves as at December 31, 2019 – Forecast Prices and Costs

RESERVES CATEGORY	Light and Medium Oil		Natural Gas		Natural Gas Liquids		TOTAL	
	Gross (Mbbbl)	Net (Mbbbl)	Gross (MMcf)	Net (MMcf)	Gross (MBbl)	Net (MBbl)	Gross (Mboe)	Net (Mboe)
Proved Reserves								
Proved Developed Producing	52.7	51.1	2,529	2,398	33.1	23.0	507.4	473.8
Proved Developed Non-Producing	45.6	43.7	211	201	2.7	2.4	86.6	79.5
Proved Undeveloped	557.9	488.8	2,890	2,705	39.9	34.6	1,079.5	974.2
Total Proved	656.2	583.6	5,631	5,304	75.7	59.9	1,670.5	1,527.5
Probable	800.8	665.9	4,689	4,382	61.5	50.5	1,643.7	1,446.6
Total Proved Plus Probable Reserves	1,457.0	1,249.5	10,319	9,685	137.2	110.5	3,314.1	2,974.1

Net Present Value of Future Net Revenue as at December 31, 2019 – Forecast Prices and Costs

RESERVES CATEGORY	BEFORE INCOME TAXES DISCOUNTED AT (% / YEAR)					AFTER INCOME TAXES DISCOUNTED AT (% / YEAR)				
	0	5	10	15	20	0	5	10	15	20
	(in \$ thousands)					(in \$ thousands)				
Proved Reserves										
Proved Developed Producing	(2,712)	(798)	(134)	134	251	(2,712)	(798)	(134)	134	251
Proved Developed Non-Producing	1,959	1,780	1,640	1,526	1,432	1,959	1,780	1,640	1,526	1,432

RESERVES CATEGORY	BEFORE INCOME TAXES DISCOUNTED AT (% / YEAR)					AFTER INCOME TAXES DISCOUNTED AT (% / YEAR)				
	0	5	10	15	20	0	5	10	15	20
	(in \$ thousands)					(in \$ thousands)				
Proved Undeveloped	8,758	5,200	2,734	1,042	(131)	8,758	5,200	2,734	1,042	(131)
Total Proved	8,005	6,182	4,240	2,702	1,552	8,005	6,182	4,240	2,702	1,552
Probable	27,511	20,384	15,583	12,245	9,837	23,105	17,466	13,565	10,799	8,770
Total Proved Plus Probable	35,516	26,567	19,823	14,947	11,389	31,110	23,648	17,805	13,500	10,322

Total Future Net Revenue (Undiscounted) as at December 31, 2019 – Forecast Prices and Costs

RESERVES CATEGORY	Total Future Revenue (Undiscounted in \$ thousands)							
	Revenue	Royalties	Operating Costs	Development Costs	Abandonment and Reclamation Costs	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
Total Proved	71,981	7,378	31,595	18,454	6,548	8,005	0	8,005
Total Proved plus Probable	154,129	19,510	59,858	31,847	7,398	35,516	4,406	31,110

Net Present Value of Future Net Revenue by Production Type as at December 31, 2019 – Forecast Prices and Costs

CATEGORY	Product Type	Future Net Revenue Before Income Taxes (Discounted at 10%/Year) (\$ Millions)	Unit Value Before Income Taxes (Discounted at 10%/Year) (\$/BOE) ⁽¹⁾
Proved	Light And Medium Crude Oil (Including solution gas and associated by-products)	3,314	2.65
	Conventional Natural Gas (Including associated by-products) ⁽²⁾	926	3.32
Total		4,240	
Proved Plus Probable	Light And Medium Crude Oil (Including solution gas and associated by-products)	18,605	7.11
	Conventional Natural Gas (Including associated by-products) ⁽²⁾	1,218	3.41
Total		19,823	

Notes:

- (1) Unit values are based on net reserves.
(2) Includes corporate Gas Cost Allowance, if applicable.

Forecast Prices Used in Estimates

The forecast cost and price assumptions assume increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs. Crude oil and natural gas benchmark reference pricing, inflation and exchange rates utilized in the Sproule Report were Sproule's forecasts, as at December 31, 2019, as follows:

Year	Canadian Light Sweet Crude 40° API (\$Cdn/bbl)	Western Canada Select 20.5° API (\$Cdn/bbl)	Alberta AECO-C Spot (\$Cdn/MMBT U)	Edmonton Pentanes Plus (\$Cdn/bbl)	Edmonton Butane (\$Cdn/bbl)	Edmonton Propane (\$Cdn/bbl)	Capital / Operating Cost Inflation Rate (%/Yr) ⁽¹⁾
Historical							
2019	68.87	58.77	1.8	71.39	23.71	17.16	-0.6% / 0.7%
Forecast							
2020	73.84	59.81	2.04	76.32	37.72	25.07	0.0%
2021	78.51	63.98	2.27	80.52	43.9	31.84	1.0%
2022	78.73	63.77	2.81	80.00	47.74	32.43	2.0%
2023	80.30	65.04	2.89	81.68	48.69	33.26	2.0%
2024	81.91	66.34	2.98	83.38	49.67	34.12	2.0%
2025	83.54	67.67	3.06	85.13	50.66	34.99	2.0%
2026	85.21	69.02	3.15	86.90	51.67	35.88	2.0%
2027	86.92	70.40	3.24	88.72	52.71	36.78	2.0%

Year	Canadian Light Sweet Crude 40° API (\$Cdn/bbl)	Western Canada Select 20.5° API (\$Cdn/bbl)	Alberta AECO-C Spot (\$Cdn/MMBT U)	Edmonton Pentanes Plus (\$Cdn/bbl)	Edmonton Butane (\$Cdn/bbl)	Edmonton Propane (\$Cdn/bbl)	Capital / Operating Cost Inflation Rate (%/Yr) ⁽¹⁾
2028	88.66	71.81	3.33	90.57	53.76	37.71	2.0%
2029	90.43	73.25	3.42	92.45	54.84	38.65	2.0%
2030	92.24	74.71	3.51	94.38	55.93	39.61	2.0%
Thereafter			Escalation rate of 2%				

Notes:

(1) Inflation rates for forecasting costs only. Prices inflated at 2% where applicable.

Reconciliations of Changes in Gross⁽¹⁾ Reserves as at December 31, 2019 – Forecast Prices and Costs

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

Factors	Light and Medium Crude			Conventional Natural Gas			Natural Gas Liquids			Total		
	Proved (mbl)	Probable (mbl)	Proved and Probable (mbl)	Proved (mmcf)	Probable (mmcf)	Proved and Probable (mmcf)	Proved (mbl)	Probable (mbl)	Proved and Probable (mbl)	Proved (mboe)	Probable (mboe)	Proved and Probable (mboe)
December 31, 2018	233.1	545.7	778.7	4,858.0	3,843.0	8,701.0	69.1	55.0	124.1	1,111.9	1,241.1	2,353.0
Extensions	387.3	365.3	752.6	1,279.0	1,576.0	2,855.0	19.0	20.9	39.9	619.5	648.9	1,268.3
Dispositions	(16.8)	(4.4)	(21.2)	(5.1)	(1.5)	(6.6)	(0.1)	-	(0.1)	(17.8)	(4.7)	(22.4)
Economic Factors	(8.7)	1.8	(6.9)	(172.9)	(6.2)	(179.1)	(2.3)	-	(2.3)	(39.8)	0.8	(39.1)
Technical Revisions	70.7	(107.5)	(36.8)	73.9	(723.3)	(649.4)	(4.7)	(14.4)	(19.1)	78.4	(242.5)	(164.1)
Production	(9.4)	-	(9.4)	(401.9)	-	(401.9)	(5.3)	-	(5.3)	(81.7)	-	(81.7)
December 31, 2019	656.2	800.8	1,457.0	5,631.0	4,688.0	10,319.0	75.7	61.5	137.2	1,670.5	1,643.7	3,314.1

Notes:

- (1) Gross Reserves means the Corporation's working interest reserves before calculation of royalties and before consideration of the Corporation's royalty interests.
- (2) Technical Revisions also include changes in reserves associated with changes in operating costs, capital costs and commodity price offsets.
- (3) No reconciliations were required due to discoveries or acquisitions.

Additional Information Relating to Reserves Data

Undeveloped Reserves

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

The Corporation's proved and probable undeveloped reserves are planned to be developed within the next two years. In some cases, it may take longer than two years 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 pricing, operating and capital expenditure fluctuations); (ii) changing technical conditions (including production anomalies, such as water breakthrough or accelerated depletion); (iii) multi-zone developments (for instance, a prospective formation completion may be delayed until the initial completion formation is no longer economic); (iv) a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and (v) surface access issues (including those relating to land owners, weather conditions and regulatory approvals).

Proved Gross Undeveloped Reserves

<u>Year</u>	<u>Light and Medium Oil (Mbbbl)</u>		<u>Natural Gas (MMcf)</u>		<u>Natural Gas Liquids (Mbbbl)</u>	
	<u>First Attributed</u>	<u>Cumulative at Year End</u>	<u>First Attributed</u>	<u>Cumulative at Year End</u>	<u>First Attributed</u>	<u>Cumulative at Year End</u>
December 31, 2017	-	99	-	833	-	10
December 31, 2018	-	119	-	1,119	-	16
December 31, 2019	498	558	1,790	2,890	26	40

Proved undeveloped reserves comprise approximately 65% of Return's total proved reserves on a Boe basis. Proved undeveloped reserves of 1,080 Mboe were assigned by Sproule in accordance with NI 51-101. In general, proved undeveloped reserves were assigned to certain properties as a result of the Corporation's capital program. Return plans to convert the undeveloped reserves to proved developed producing reserves over the next three years through future capital spending.

Probable Gross Undeveloped Reserves

<u>Year</u>	<u>Light and Medium Oil (Mbbbl)</u>		<u>Natural Gas (MMcf)</u>		<u>Natural Gas Liquids (Mbbbl)</u>	
	<u>First Attributed</u>	<u>Cumulative at Year End</u>	<u>First Attributed</u>	<u>Cumulative at Year End</u>	<u>First Attributed</u>	<u>Cumulative at Year End</u>
December 31, 2017	-	86	-	704	-	9
December 31, 2018	281	514	1,266	2,671	18	39
December 31, 2019	366	764	1,576	3,908	21	51

Probable undeveloped reserves were assigned by Sproule in accordance with NI 51-101 requirements and standards. Return's probable undeveloped reserves amount to 1,467 MBoe and represent about 88% of the total probable reserves. Probable undeveloped reserves are assigned for similar reasons and generally to the same properties as proved undeveloped reserves, but also meet the requirements of the reserve classification to which they belong. 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. Return plans to convert the probable undeveloped reserves to proved developed producing reserves over the next five years as a result of future capital spending.

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 or economic data. These estimates may change substantially as additional data from ongoing development activities and production performance become available and as economic conditions impacting oil and gas prices and costs change. The reserve estimates contained herein are based on forecast prices, production forecasts, prices and economic conditions.

As circumstances change and additional data becomes 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, the subjective decisions, new geological or production information and a changing environment may impact these estimates. Revisions to reserve estimates can arise from changes in year-end oil and gas prices, and reservoir performance. Such revisions can either be positive or negative.

Future Development Costs

The following table shows the development costs anticipated in the next 5 years, which have been deducted in the estimation of the Corporation's future net revenues of the reserves evaluated in the Sproule Report.

Year	Forecast Prices and Cost (Undiscounted) (In \$ thousands)	
	Proved Reserves	Proved Plus Probable
2020	5,675	11,325
2021	12,779	20,522
2022	-	-
2023	-	-
2024	-	-
	18,454	31,847

The Corporation has been successful in raising the required capital through equity financings. The Corporation expects to be able to finance its future development costs with its positive working capital and projected cash flow from operations.

Other Oil and Gas Information

Oil and Natural Gas Wells and Properties

The following table sets forth the number of wells in which the Corporation held a working interest as at December 31, 2019, all of which are in the Province of Alberta:

Alberta area	Category	Oil Well		Natural Gas Wells		Other Wells ⁽¹⁾	
		Gross	Net	Gross	Net	Gross	Net
Valhalla/Rycroft	Producing	5.0	4.1	9.0	8.1	-	-
	Non-Producing ⁽²⁾	16.0	6.6	31.0	17.7	-	-
Other	Producing	2.0	1.0	2.0	0.8	4.0	1.3
	Non-Producing ⁽²⁾	21.0	9.8	83.0	49.0	5.0	2.0
Total	Producing	7.0	5.1	11.0	8.9	4.0	1.3
	Non-Producing ⁽²⁾	37.0	16.4	114.0	66.7	5.0	2.0

Notes:

(1) Other wells include water disposal wells, water injection wells, coalbed methane wells, cased wells with no type, and unknown.

(2) Non-producing wells include wells that have been downhole abandoned but not yet fully reclaimed.

The Corporation held working interests in 21 gross (10.7 net) oil wells and 40 gross (25.8 net) gas wells in the Valhalla/Rycroft area of Alberta. Combined with these assets is ownership in several gathering systems. The Corporation also operates and owns 100% of the Rycroft Gas Plant located at 15-11-76-6W6.

During the financial year ended December 31, 2019, the Corporation sold 11 gross (2.4 net) oil wells in the Valhalla/Rycroft area.

The Valhalla/Rycroft area has one well with reserves assigned that has been shut in since October 2016. The well produces slightly sour gas and is currently unable to produce to the sweet gas facility that it is pipelined to. The Corporation is planning to return this well to production with a flare permit in the short term and with a new pipeline in the medium term.

Net production from the Valhalla/Rycroft area averaged 213 BOE per day from January 1 to December 31, 2019, representing 95% of the Corporation's total 2019 production. The other areas make up the remaining 5% of production.

Properties with No Attributed Reserves

The following table sets out the Corporation's mineral rights holdings without reserves as at December 31, 2019:

Province	Gross Acres	Net Acres	Net Acres Expiring Within One Year
Alberta Undeveloped	4,000	3,043	nil
Alberta Developed	13,600	7,441	nil
Alberta Total	17,600	10,484	nil

Undeveloped acres are lands that do not have wellbores and have not been assigned reserves. Developed acres are lands with wellbores that have not been assigned reserves. The total acreage shown represents the Corporation's mineral rights on properties excluding those with reserves assigned. The Corporation has no material work commitments related to our undeveloped acreage in 2020.

Significant Factors or Uncertainties Relevant to Properties with No Attributed Reserves

There are several economic factors and significant uncertainties that affect the anticipated development of Return's properties with no attributed reserves. Return will be required to make capital expenditures in order to prove, exploit, develop and produce oil and natural gas from these properties in the future. If Return's cash flow from operations or current cash balance is not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or, if available, on terms acceptable to Return. Failure to obtain such financing on a timely basis could cause Return to forfeit its interest in certain properties, miss certain opportunities and reduce or terminate its operations. The inability of Return to access sufficient capital for its exploration and development purposes could have a material adverse effect on Return's ability to execute its business strategy to develop these prospects.

Return estimates the total cost of future abandonment and reclamation for its existing wells, including their associated production facilities and infrastructure, and the expected timing of the costs to be incurred in future periods. The Corporation has a process for estimating these costs, which considers past experience, applicable current regulations, technology and industry standards, actual and anticipated costs, the type and depth of the well (or the nature and size of the facility), and the geographic location. As at December 31, 2019, the Corporation has estimated its share of the total abandonment and reclamation costs for its existing wells and facilities to be \$7.4 million undiscounted and uninflated. Based on an inflation rate of 2.0%, the undiscounted amount of the estimated future cash flows required to settle the obligation is \$9.8 million as at December 31, 2019 (approximately \$3.2 million discounted at 10%), of which Return expects to pay approximately \$1.1 million over the next three financial years.

Of the undiscounted future abandonment and reclamation costs to be incurred over the life of Return's proved plus probable reserves, approximately \$7.4 million (undiscounted) has been deducted in estimating the future net revenue in the Sproule Report, which represents the Corporation's total existing estimated abandonment and reclamation costs, plus all forecast estimates of abandonment and reclamation costs attributable to future development activity associated with the reserves. The Sproule Report does not include future abandonment and reclamation costs for inactive properties that were not included in Sproule's evaluation as at December 31, 2019.

Forward Contracts

The Corporation does not have any forward sales contracts as at December 31, 2019. Subsequent to December 31, 2019, the Corporation entered into risk management contracts to fix the price of 750 GJ per day of natural gas production at \$1.54 per GJ from April 1 to October 31, 2020.

Tax Horizon

As at December 31, 2019, the Corporation's total available tax pools are estimated to be \$19.9 million, of which \$15.4 million are non-capital losses. The Corporation is unable to estimate when income taxes may become payable as it is dependent on the level of future commercial exploration and development success.

Costs Incurred

The following table summarizes the Corporation's consolidated property acquisition costs, exploration costs and development costs (before property dispositions) incurred during the year ended December 31, 2019. The amounts reported as unproved acquisition costs and exploration costs are consistent with capital expenditures classified as exploration and evaluation assets under IFRS. The amounts reported as proved acquisition costs and development costs are consistent with capital expenditures classified as property, plant and equipment under IFRS.

Province	Acquisition Costs		Exploration Costs	Development Costs
	Proved Properties	Unproved Properties		
Alberta, Canada	-	-	-	\$33,922

The Corporation completed non-core property dispositions during 2019 for aggregate cash proceeds of \$264,793 after closing adjustments, of which, \$50,000 related to unproved properties and \$214,793 related to proved properties.

Exploration and Development Activities

The following table sets forth the gross and net development and exploration wells drilled during the financial year ended December 31, 2019:

ALBERTA	Development Wells		Exploration Wells	
	Gross	Net	Gross	Net
Oil	-	-	-	-
Gas	-	-	-	-
Service	-	-	-	-
Stratigraphic	-	-	-	-
Dry and Abandoned	-	-	-	-
TOTAL	-	-	-	-

Current development projects are focused around vertical and horizontal well development drilling for conventional light oil and gas recovery in the Rycroft area of Alberta.

Production Estimates

The following table discloses the total volume of production estimated by the Sproule Report for the year 2020 reflected in the estimates of gross proved reserves and gross probable reserves disclosed under "Reserves Data (Forecast Prices and Costs)", above.

RESERVES CATEGORY	Light and Medium Oil bbl/d	Natural Gas MCF/d	Natural Gas Liquids bbl/d	Total boe/d
Valhalla/Rycroft				
Proved	141	1,512	20	412
Probable	133	626	8	246
Total Proved Plus Probable Reserves	274	2,138	28	658
Other				
Proved	4	31	1	10
Probable	0	-	-	0
Total Proved Plus Probable Reserves	4	31	1	10
Total				
Proved	145	1,543	20	422
Probable	134	626	8	246
Total Proved Plus Probable Reserves	279	2,169	28	668

Production History

The following table sets forth the Corporation's average daily production volume, on a Corporation interest basis, and the average operating netback (loss) received for each fiscal quarter in 2019 and for the entire year.

	Three Months Ended, 2019				Year Ended
	31-Mar	30-Jun	30-Sep	31-Dec	31-Dec-19
Average Daily Production					
Light and Medium Oil (bbl/d)	30	24	24	25	26
Natural Gas Liquids (bbl/d)	17	13	12	20	15
Natural Gas (mcf/d)	1,060	1,199	1,077	1,070	1,102
Total (boe/d)	224	237	215	223	225
Aggregate Sales ⁽¹⁾ (\$)	500,997	296,217	256,342	437,763	1,491,319
Average Sales Price (\$/boe)	24.90	13.74	12.94	21.33	18.18
Processing and other (\$/boe)	1.45	1.53	1.89	1.78	1.66
Royalties (\$/boe)	(0.05)	1.30	(0.12)	(0.15)	0.26
Operating expenses (\$/boe)	(19.83)	(23.97)	(23.51)	(30.91)	(24.58)
Operating netback (loss) ⁽¹⁾ (\$/boe)	6.47	(7.40)	(8.80)	(7.95)	(4.48)

Notes:

(1) "Aggregate sales" and "operating netback (loss)" are non-IFRS measures. See "Special Note Regarding Forward Looking Statements and Other Information – Non-IFRS Measures" for more information.

DIVIDEND POLICY

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

DESCRIPTION OF SHARE CAPITAL

The Corporation is authorized to issue an unlimited number of Common Shares, an unlimited number of Preferred Shares, issuable in series, and an unlimited number of Special Shares.

As of December 31, 2019 and the date hereof, there are 2,610,551,651 Common Shares and 1,620,350,000 Warrants issued and outstanding. See "General Development of the Business – Three Year History – Financial Year Ended December 31, 2019", above. There are no Options, Preferred Shares or Special Shares outstanding as at the date hereof.

Common Shares

The holders of Common Shares are entitled to receive notice of and attend all meetings of shareholders of Return (except meetings at which only holders of a specified class or series of shares are entitled to vote) and are entitled to one vote per Common Share. Subject to the prior rights of holders of Preferred Shares and Special Shares, holders of Common Shares are entitled to dividends, if, as and when declared by the Board, and, in the event of the liquidation, dissolution or winding-up of Return, or any other distribution of assets among its shareholders for the purpose of winding-up its affairs, to receive on a pro-rata basis all of the remaining property of Return.

Preferred Shares

The Preferred Shares may be issued from time to time in one or more series, each series consisting of a number of Preferred Shares as determined by the Board, who may fix the designations, rights, privileges, restrictions and conditions attaching to the shares of each series of Preferred Shares. The Preferred Shares of each series shall, with respect to dividends, liquidation, dissolution or winding-up of the Corporation, whether voluntary or involuntary, or any other distribution of the assets of the Corporation among its Shareholders for the purpose of winding up its affairs, shall be entitled to preference over the Common Shares and the shares of any other class ranking junior to the Preferred

Shares. The Preferred Shares of any series may also be given such other preferences and priorities over the Common Shares and any other shares of the Corporation ranking junior to such series of Preferred Shares.

Series I Preferred Shares

In addition to the rights attaching to Preferred Shares as a class, Series I Preferred Shares rank in priority to the Common Shares, are redeemable by the Corporation and are convertible at the option of the holder as described below. Holders of Series I Preferred Shares are not entitled to receive notice of, attend or vote at any meeting of the shareholders of Return except where specifically provided by the ABCA. In the event of the dissolution, liquidation or winding-up of Return, whether voluntary or involuntary, or other distribution of assets of Return among its Shareholders for the purpose of winding-up its affairs, the holders of the Series I Preferred Shares are entitled to receive \$1.00 from the assets and property of Return for each Series I Preferred Share held by them, before any amount shall be paid or any property or assets of Return distributed to the holders of any Common Shares or shares of any other class or series ranking junior to the Series I Preferred Shares. The Corporation is prohibited from issuing any Special Shares at any time while any Series I Preferred Shares are issued and outstanding.

The holders of Series I Preferred Shares may, at any time and at their option, convert all or part of the Series I Preferred Shares into units of Return. Each unit is comprised of one (1) Common Share and one-half (1/2) of a Warrant. The number of units issuable upon the conversion of the Series I Preferred Shares is equal to the number of Series I Preferred Shares to be converted multiplied by \$1.00 and divided by the average of the trading price of the common shares on the TSXV during the twenty (20) consecutive day period immediately prior to conversion. Each whole Warrant entitles the holder to purchase one (1) Common Share until October 21, 2021 upon payment of the Common Share purchase warrant exercise price. The Corporation may at its sole discretion redeem the Series I Preferred Shares at any time upon cash payment of \$1.00 per Series I Preferred Share.

In connection with the Recapitalization Transaction, the holder of the 2,000,000 Series I Preferred Shares authorized Return to amend the rights, privileges, restrictions and conditions of such shares to permit the purchase of all outstanding Series I Preferred Shares by Return for an aggregate of \$10.00, and all such shares were repurchased by the Corporation and cancelled on December 19, 2019.

Special Shares

The holders of Special Shares are not entitled to receive notice of and attend meetings of shareholders of Return, unless specifically entitled to vote pursuant to the ABCA or the meeting is called to consider any matter in respect of which the holders of the Special Shares would be entitled to vote separately as a class or for the purpose of authorizing the dissolution of the Corporation or the sale, lease or exchange of all or substantially of the Corporation's property. Holders of Special Shares are entitled to dividends, if, as and when declared by the Board, and dividends may only be declared and set aside for payment to holders of Common Shares or any other shares ranking junior to the Special Shares if, at the time of such declaration, the realizable value of the assets of the Corporation would be less than the aggregate Redemption Amount (as defined below) available to the holders of Special Shares. In the event of the liquidation, dissolution or winding-up of Return, or any other distribution of assets among its Shareholders for the purpose of winding-up its affairs, the holders of Special Shares are entitled to receive from the assets of the Corporation a sum equivalent to the aggregate Redemption Amount before any amount shall be paid to holders of Common Shares or shares of any other class ranking junior to the Special Shares.

Subject to the requirements of the ABCA, the Corporation may, and the holders of Special Shares may require the Corporation to, redeem any outstanding Special Shares on payment of the redemption price, being the Redemption Amount for all Special Shares divided by the number of Special Shares issued and outstanding. The aggregate redemption amount (the "**Redemption Amount**") in respect of the Special Shares is equal to the aggregate fair market value of the property acquired by the Corporation upon the issuance of such Special Shares as confirmed by the Board by resolution within 60 days of the issuance of such Special Shares.

Stock Options

The Corporation has a stock option plan under which Options to purchase Common Shares may be granted to officers, directors, employees and consultants. The Board has approved a policy of reserving up to 10% of the outstanding Common Shares for issuance to eligible participants. Under the plan, all Options have a maximum term of five years.

Warrants

As of the date hereof, the only outstanding Warrants are the Recap Warrants issued pursuant to the 2019 Private Placement. For more information regarding the terms of the Recap Warrants, see “*General Development of the Business – Three Year History – Financial Year Ended December 31, 2019*”, above. All Warrants issued prior to the 2019 Private Placement, including as part of the previously described Vertex Offering and other non-brokered private placements (see “*General Development of the Business*” in this Annual Information Form) have expired or were surrendered for cancellation in connection with the Recapitalization Transaction.

MARKET FOR SECURITIES

The Common Shares are listed on the TSXV under the symbol “RTN”. The following table sets the price range and trading volume of these securities for the period from January 1, 2019 to December 31, 2019, as reported by the TSXV:

Month	Common Shares		
	High	Low	Volume
January	\$0.03	\$0.02	603,000
February	\$0.03	\$0.02	56,200
March	\$0.03	\$0.03	273,900
April	\$0.04	\$0.02	1,881,400
May	\$0.03	\$0.02	412,400
June	\$0.03	\$0.02	458,600
July	\$0.03	\$0.02	407,100
August	\$0.02	\$0.02	178,000
September	\$0.02	\$0.01	333,100
October	\$0.01	\$0.01	138,000
November	\$0.06	\$0.01	13,003,500
December	\$0.06	\$0.05	10,905,200

PRIOR SALES

During the twelve months preceding the date hereof, no securities have been issued by the Corporation that are outstanding but not listed or quoted on a marketplace, except as set forth below.

Date of Issuance	Class of Securities	Number of Securities Issued	Exercise Price
December 19, 2019	Recap Warrants	1,620,350,000	\$0.01 ⁽¹⁾

Notes:

- (1) Each Recap Warrant entitles the holder to purchase one Common Share at the Exercise Price for a period of five years. The Recap Warrants vest and become exercisable as to one third upon the Market Price equaling or exceeding 100% of the Exercise Price, an additional one-third upon the Market Price equaling or exceeding 150% of the Exercise Price and a final one-third upon the Market Price equaling or exceeding 200% of the Exercise Price. For more information, see “*General Development of the Business – Three Year History – Financial Year Ended December 31, 2019*”.

DIRECTORS AND OFFICERS

Directors and Officers as at the Date Hereof

The following table sets forth the names and municipalities of residence of the New Board and the New Management Team of the Corporation, their respective positions and offices with the Corporation and date first appointed or elected

as a director and/or officer and their principal occupation(s) within the past five years. See “General Development of the Business – Three Year History – Financial Year Ended December 31, 2019”, above.

Name and Municipality of Residence	Position Held (and First Date Appointed as a Director)	Principal Occupation Within the Past Five Years
Richard F. McHardy ⁽¹⁾⁽⁴⁾ <i>Calgary, Alberta</i>	Executive Chairman and Director (December 19, 2019)	Executive Chairman of Return since December 19, 2019. Prior thereto, President, Chief Executive Officer and a director of Spartan Energy Corp. (“ Spartan Energy ”) from December 2013 to May 2018.
Fotis Kalantzis <i>Calgary, Alberta</i>	President, Chief Executive Officer and Director (December 19, 2019)	President and Chief Executive Officer of Return since December 19, 2019. Prior thereto, Senior Vice President, Exploration, of Spartan Energy from March 2016 to May 2018; Vice President, Exploration, of Spartan Energy from December 2013 to March 2016.
Geri Greenall <i>Calgary, Alberta</i>	Chief Financial Officer	Chief Financial Officer of Return since December 19, 2019. Independent director, Chair of the Reserves Evaluation Committee and a member of the Audit Committee of Kelt Exploration Ltd. since December 2017. Co-founder and Chief Financial Officer of Camber Capital Corp., a fund manager offering private client and institutional fund management services, from May 2011 to December 2019.
Thanos Natras <i>Calgary, Alberta</i>	Vice President, Exploration	Vice President, Exploration, of Return since December 19, 2019. Prior thereto, Team Lead for southeast Saskatchewan operations with Vermilion Energy Inc. (“Vermilion”) from May 2018 to October 2018. Prior thereto, Manager, Geoscience, and Senior Geologist of Spartan Energy from January 2014 to May 2018.
Craig Martin <i>Calgary, Alberta</i>	Vice President, Operations	Vice President, Operations, of Return since December 19, 2019. Prior thereto, Professional Engineer with Vermilion from May 2018 to October 2019. Prior thereto, Manager, Drilling and Completions, at Spartan Energy from February 2014 to May 2018.
Mark Hodgson <i>Calgary, Alberta</i>	Vice President, Corporate Development	Vice President, Corporate Development, of Return since December 19, 2019. Prior thereto, Vice President, Operations, at Obsidian Energy Ltd. (“ Obsidian ”) from May 2018 to March 2019 and Vice President, Business Development, at Obsidian from February 2017 to May 2018. Prior thereto, Vice President, New Ventures, and In-Country Manager for Bankers Petroleum Ltd. in Albania, as well as the General Director for its subsidiaries in Croatia, Hungary and Romania, from December 2013 to December 2016.
Brendan Paton <i>Calgary, Alberta</i>	Manager, Engineering	Manager, Engineering, of Return since December 19, 2019. President of Canoe Point Energy Ltd. from June 2018 to December 2019. Prior thereto, Production Engineer at Shell Canada Limited from July 2011 to June 2018.
Sanjib (Sony) Gill <i>Calgary, Alberta</i>	Corporate Secretary	Partner at Stikeman Elliott LLP, a national law firm, practicing primarily in the areas of corporate finance, securities and mergers and acquisitions transactions. Prior thereto, partner at another national law firm.

Name and Municipality of Residence	Position Held (and First Date Appointed as a Director)	Principal Occupation Within the Past Five Years
Donald Archibald ⁽¹⁾⁽³⁾ <i>Calgary, Alberta</i>	Director (December 19, 2019)	Independent businessman; President of Cypress Energy Corp., a private investment company since March 2008. Mr. Archibald also serves on the board and various committees of Cequence Energy Inc., Palisade Capital, Panorama Mountain Resort, Petronas Energy Canada, Return Energy Inc., and Serafina Energy Ltd.
Reginald J. Greenslade ⁽²⁾⁽⁴⁾ <i>Calgary, Alberta</i>	Director (December 19, 2019)	Independent businessman since February 2013. Director of Spartan Energy from December 2013 to May 2018. President and Director of Tuscany International Drilling Inc. from April 2010 to February 2013.
Kevin Overstrom ⁽¹⁾⁽²⁾⁽³⁾ <i>Etobicoke, Ontario</i>	Director (December 19, 2019)	Founder and a principal of KO Capital Advisors Ltd., a private investment company, since September 2018. Prior thereto, Vice Chairman, Co-Head of Energy Investment Banking at GMP FirstEnergy (formerly GMP Securities) from June 2014 to September 2018.
Tamara MacDonald ⁽²⁾⁽³⁾⁽⁴⁾ <i>Calgary, Alberta</i>	Director (December 19, 2019)	Director of Southern Energy Corp. since December 2018. Prior thereto, Senior Vice President, Corporate and Business Development, of Crescent Point Energy Corp. from October 2004 to July 2018.

Notes:

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

As at the date hereof, the New Board and the New Management Team of the Corporation, and their associates and affiliates, as a group, whether, beneficial, direct or indirect, own 1,526,807,000 Common Shares, representing approximately 58.50% of the currently outstanding Common Shares.

The directors listed above will hold office until the next annual meeting of the Corporation or until their successors are elected or appointed.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

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

- (a) no director or executive officer is, or within the ten years prior to the date hereof has been, a director, chief executive officer or chief financial officer of any other issuer that, while that person was acting in that capacity: (i) was the subject of a cease trade order, an order similar to a cease trade order or an order that denied the relevant issuer access to any exemption under securities legislation for a period of more than 30 consecutive days; or (ii) was subject to a cease trade order, an order similar to a cease trade order or an order that denied the relevant issuer access to any exemptions under securities legislation that was issued after the director or officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer;
- (b) no director, executive officer or any shareholder holding a sufficient number of securities of the Corporation to affect materially the control of the Corporation, or a personal holding company of any such person: (i) is, or within the ten years prior to the date hereof has been, a director or executive officer that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or

compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; or (ii) has, within the 10 years preceding the date of this Annual Information Form, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or being subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold the assets of the individual; and

- (c) no director, executive officer or any shareholder holding a sufficient number of securities of the Corporation to affect materially the control of the Corporation, within the last 10 years, has: (i) been subject to any penalties or sanctions imposed by a court relating to Canadian securities legislation or by a Canadian securities regulatory authority or has entered into a settlement agreement with the Canadian securities regulatory authority; or (ii) been subject to any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

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

Conflicts of Interest

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

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

To the knowledge of the Corporation, there are no legal proceedings or regulatory actions material to the Corporation to which the Corporation is a party, or was a party to in 2019, or of which any of its properties is the subject matter, or was the subject matter of in 2019, nor are there any such proceedings known to the Corporation to be contemplated. There have been no penalties or sanctions imposed against the Corporation by a court relating to securities legislation or by a securities regulatory authority and the Corporation has not entered to any settlement agreements with a court or securities regulatory authority.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Sanjib (Sony) Gill, the Corporate Secretary of the Corporation, is a partner of the national law firm Stikeman Elliott LLP, which law firm rendered legal services to the Corporation.

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

AUDITOR, TRANSFER AGENT AND REGISTRAR

The auditor of the Corporation is MNP LLP, Chartered Accountants at its office located at 1500, 640 – 5th Avenue S.W., Calgary, Alberta, T2P 3G4.

The transfer agent and registrar for the Common Shares is Computershare Trust Company of Canada at its office located at 600, 530 – 8th Avenue S.W., Calgary, Alberta, T2P 3S8.

MATERIAL CONTRACTS

Except as disclosed below and other than contracts entered into in the ordinary course of business, there have been no material contracts entered into by the Corporation within the most recently completed financial year, or before the most recently completed financial year that are still in effect.

On November 21, 2019, the Corporation entered into a definitive reorganization and investment agreement with the Initial Investors, which provided for: (a) the 2019 Private Placement; and (b) the appointment of the New Management Team and New Board, a copy of which has been filed on SEDAR at www.sedar.com on November 29, 2019. See “*General Development of the Business – Three Year History – Financial Year Ended December 31, 2019*”, above.

INTERESTS OF EXPERTS

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a statement, report or valuation described or included in a filing, or referred to in a filing, made under NI 51-102 by Return during, or related to, Return’s most recently completed financial year other than Sproule, the independent reserve evaluators, and MNP LLP, Return’s auditors.

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

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

ADDITIONAL INFORMATION

Additional information, including directors’ and officers’ remuneration and indebtedness, principal holders of Common Shares and securities authorized for issuance under equity compensation plans and interests of insiders in material transactions, if applicable, is contained in the Corporation’s information circular for its most recent annual meeting of Shareholders that involved the election of directors, which has been filed on SEDAR at www.sedar.com.

Additional financial information is provided for in Return’s financial statements and management’s discussion and analysis for the year ended December 31, 2019. Documents affecting the rights of security holders, along with other information relating to the Corporation, may be found on SEDAR at www.sedar.com. Additional copies of this Annual Information Form and the materials listed in the preceding paragraph are available on the foregoing basis and upon request by contacting the Corporation at its offices at 202, 1201 – 5th Street S.W., Calgary, Alberta T2R 0Y6 or by phone at (403) 265-8011.

APPENDIX A

REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR

FORM 51-101F2

To the Board of Directors of Return Energy Inc. (the “**Company**”):

1. We have evaluated the Company’s reserves data as at December 31, 2019. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2019, estimated using forecast prices and costs.
2. The reserves data are the responsibility of the Company’s management. Our responsibility is to express an opinion on the reserves data based on our evaluation.
3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the “**COGE Handbook**”), maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).
4. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.
5. The following table shows the net present value of future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated for the year ended December 31, 2019, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company’s management and Board of Directors:

Independent Qualified Reserves Evaluator or Auditor	Effective Date	Location of Reserves (Country)	Net Present Value of Future Net Revenue Before Income Taxes (10% Discount Rate)			
			Audited (M\$)	Evaluated (M\$)	Reviewed (M\$)	Total (M\$)
Sproule	December 31, 2019	Canada	_____	_____	_____	_____
Total			<u>Nil</u>	<u>19,823</u>	<u>Nil</u>	<u>19,823</u>

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.
7. We have no responsibility to update our report referred to in paragraph 5 for events and circumstances occurring after the effective date of our report, entitled “Evaluation of the P&NG Reserves of Spartan Delta Corp. (As of December 31, 2019)”.
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:

Sproule Associates Limited
Calgary, Alberta
March 31, 2020

(signed) "Tamara Warren"

Tamara Warren, P. Eng.
Petroleum Engineer

(signed) "Douglas McNichol"

Douglas McNichol, P. Eng.
Senior Manager, Engineering

(signed) "Alec Kovaltchouk"

Alec Kovaltchouk, P. Geo.
VP, Geoscience

APPENDIX B

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

This is the form referred to in item 3 of section 2.1 of National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* (“NI 51-101”).

1. Terms to which a meaning is ascribed in *NI 51-101* have the same meaning in this form.
2. The report referred to in item 3 of section 2.1 of *NI 51-101* must in all material respects be as follows:

Management of Return Energy Inc. (the “**Company**”) are responsible for the preparation and disclosure of information with respect to the Company’s oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2019 estimated using forecast prices and costs.

Independent qualified reserves evaluators have 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 has reviewed the Company’s procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has, on the recommendation of the Reserves Committee, approved:

- (a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data and other oil and gas information;
- (b) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluators on the reserves data; and
- (c) the content and filing of this report.

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

(signed) “Fotis Kalantzis”
Fotis Kalantzis
President & Chief Executive Officer

(signed) “Thanos Natras”
Thanos Natras
Vice President, Exploration

(signed) “Tamara MacDonald”
Tamara MacDonald
Director

(signed) “Reginald Greenslade”
Reginald Greenslade
Director

April 7, 2020