



**KELT EXPLORATION LTD.
ANNUAL INFORMATION FORM**

**For the Year Ended
December 31, 2016**

March 10, 2017

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SELECTED DEFINITIONS

In this Annual Information Form, the following terms have the meanings set forth below, unless otherwise indicated. Additional terms relating to reserves and other oil and gas information have the meanings set forth in Appendix C – *Definitions Used for Reserves Categories*.

“**ABCA**” means the *Business Corporations Act*, R.S.A. 2000, c. B-9, as amended, including the regulations promulgated thereunder.

“**Amended and Restated Credit Agreement**” has the meaning set forth under the heading “*General Description of the Business – History of Kelt – 2015*”.

“**Annual Information Form**” means this annual information form of the Corporation dated March 10, 2017.

“**Artek**” means Artek Exploration Ltd.

“**Artek Arrangement**” means the plan of arrangement under section 193 of the ABCA involving Artek, the Corporation and the shareholders of Artek completed on April 16, 2015 pursuant to which the Corporation acquired all of the issued and outstanding common shares of Artek on the basis of 0.34 of a Common Share for each Artek common share.

“**Arrangement**” means the plan of arrangement under section 193 of the ABCA involving the Corporation, Celtic, ExxonMobil Canada, the Purchaser and the Celtic Shareholders and Celtic Debentureholders completed on February 26, 2013 pursuant to which, among other things, the Purchaser acquired all of the issued and outstanding Celtic Shares and the Corporation completed the Arrangement Acquisition.

“**Arrangement Acquisition**” means the acquisition of the Arrangement Assets by Kelt from Celtic pursuant to the Arrangement and the Asset Conveyance Agreement.

“**Arrangement Assets**” means the assets acquired by Kelt from Celtic pursuant to the Arrangement and the Asset Conveyance Agreement as more particularly described under the heading “*General Development of the Business – History of Kelt – 2013 – The Arrangement and the Arrangement Acquisition*”.

“**Asset Conveyance Agreement**” means the asset conveyance agreement between Celtic and Kelt made as of February 26, 2013.

“**Board of Directors**” means the board of directors of Kelt.

“**Cash Consideration**” has the meaning set forth under the heading “*General Development of the Business – History of Kelt – 2013 – The Arrangement and the Arrangement Acquisition*”.

“**Celtic**” means Celtic Exploration Ltd.

“**Celtic Debentureholders**” means the former holders of Celtic Debentures.

“**Celtic Debentures**” means the 5.00% convertible unsecured subordinated debentures of Celtic that were previously due April 30, 2017 and which were converted into Celtic Shares pursuant to the Arrangement as more particularly described under the heading “*General Development of the Business – History of Kelt – 2013 – The Arrangement and the Arrangement Acquisition*”.

“**Celtic Options**” means the former options to acquire Celtic Shares.

“**Celtic Shareholders**” means the former holders of Celtic Shares.

“**Celtic Shares**” means the common shares of Celtic which were acquired by the Purchaser pursuant to the Arrangement as more particularly described under the heading “*General Development of the Business – History of Kelt – 2013 – The Arrangement and the Arrangement Acquisition*”.

“**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 and Petroleum (Petroleum Society), as amended from time to time.

“**Common Shares**” means the common shares of Kelt.

“**Conversion Price**” has the meaning set forth under “*General Description of the Business – History of Kelt - 2016*”.

“**Credit Facilities**” means the credit facilities established under the Amended and Restated Credit Agreement.

“**ExxonMobil Canada**” means ExxonMobil Canada Ltd.

“**Fireweed Acquisition**” has the meaning set forth under the heading “*General Description of the Business – History of Kelt – 2013 – Developments Subsequent to the Arrangement and the Arrangement Acquisition*”.

“**IFRS**” means International Financial Reporting Standards.

“**Interest Payment Date**” has the meaning set forth under “*General Description of the Business – History of Kelt – 2016*”.

“**Kelt**” or the “**Corporation**” means Kelt Exploration Ltd.

“**Kelt Debentures**” has the meaning set forth under the heading “*General Description of the Business – History of Kelt – 2016*”.

“**Maturity Date**” has the meaning set forth under the heading “*General Description of the Business – History of Kelt – 2016*”.

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

“**NI 51-102**” means National Instrument 51-102 – *Continuous Disclosure Obligations*.

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

“**Options**” means the options to acquire Common Shares.

“**Pouce Coupe/Spirit River Acquisition**” has the meaning set forth under the heading “*General Description of the Business – History of Kelt – 2013 – Developments Subsequent to the Arrangement and the Arrangement Acquisition*”.

“**Preferred Shares**” means the preferred shares of Kelt.

“**PrivateCo**” has the meaning set forth under the heading “*General Description of the Business – History of Kelt – 2014*”.

“**PrivateCo Acquisition**” has the meaning set forth under the heading “*General Description of the Business – History of Kelt – 2014*”.

“**Purchaser**” means ExxonMobil Celtic ULC.

“**RSUs**” means the restricted share units of Kelt.

“**Share Consideration**” has the meaning set forth under the heading “*General Development of the Business – History of Kelt – 2013 – The Arrangement and the Arrangement Acquisition*”.

“**Sproule**” means Sproule Associates Limited, independent petroleum engineers of Calgary, Alberta.

“**Sproule Report**” means the report prepared by Sproule dated February 7, 2017 and effective as of December 31, 2016 entitled “*Evaluation of the P&NG Reserves of Kelt Exploration Ltd. (As of December 31, 2015)*”.

“Subscription Receipts” has the meaning set forth under the heading *“General Description of the Business – History of Kelt – 2013 – Developments Subsequent to the Arrangement and the Arrangement Acquisition”*.

“Syndicated Credit Agreement” has the meaning set forth under the heading *“General Description of the Business - History of Kelt - 2014”*.

“TSX” means the Toronto Stock Exchange.

PRESENTATION OF INFORMATION

The information contained in this Annual Information Form is presented as at December 31, 2016 except where otherwise noted.

In this Annual Information Form, unless otherwise noted, all dollar amounts are expressed in Canadian dollars.

ABBREVIATIONS AND CONVERSIONS

Abbreviations

The following abbreviations have the meanings set forth below.

AECO	Alberta Energy Company interconnect with Nova system, the Canadian benchmark for natural gas pricing
API	American Petroleum Institute
bb/d	Barrels per day
bbls	Barrels
BOE	Barrel of oil equivalent of natural gas and crude oil on the basis of one bbl of crude oil for 6 Mcf of natural gas
BOE/d	Barrel of oil equivalent per day
Lt	Long tons
Lt/d	Long tons per day
M\$	Thousands of dollars
m ³	Cubic metres
Mbbl	Thousand barrels
MBOE	Thousand barrels of oil equivalent
Mcf	Thousand cubic feet
Mcf/d	Thousand cubic feet per day
MMBtu	One million British thermal units
MMcf	Million cubic feet
MMcf/d	Million cubic feet per day
NGL	Natural gas liquids
WTI	West Texas Intermediate of Cushing, Oklahoma, the benchmark for crude oil pricing purposes

Non-GAAP Measures

Within this Annual Information Form, references are made to terms commonly used in the oil and natural gas industry. The term “netback” in this Annual Information Form is not a recognized measure under generally accepted accounting principles in Canada. Kelt uses “netback” as a key performance indicator and it is used by Kelt in operational and capital allocation decisions. It is determined by deducting royalties and operating expenses from petroleum and natural gas revenue. Readers are cautioned, however, that this measure should not be construed as an alternative to net earnings or cash flow from operating activities determined in accordance with generally accepted accounting principles in Canada as an indication of Kelt’s performance.

Conversions

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

To Convert From	To	Multiply By
Mcf	m ³	28.174
m ³	Cubic feet	35.494
Bbls	m ³	0.159
m ³	Bbls	6.293
Feet	Metres	0.305
Metres	Feet	3.281
Miles	Kilometres	1.609
Kilometres	Miles	0.621
Acres	Hectares	0.405
Hectares	Acres	2.500 (Alberta and British Columbia)
Gigajoules	MMBtu	0.950
MMBtu	Gigajoules	1.0526

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.

FORWARD-LOOKING STATEMENTS AND INFORMATION

This Annual Information Form contains forward-looking statements and forward-looking information (collectively, “**forward-looking statements**”). These statements relate to future events or Kelt’s future performance. All statements other than statements of historical fact may be forward-looking statements. In some cases, forward-looking statements can be identified by terminology such as “may”, “will”, “should”, “expect”, “plan”, “anticipate”, “believe”, “estimate”, “predict”, “potential”, “continue”, or the negative of these terms or other comparable terminology. These statements are only predictions. Actual events or results may differ materially. In addition, this Annual Information Form may contain forward-looking statements attributed to third party industry sources. Undue reliance should not be placed on these forward-looking statements, as there can be no assurance that the plans, intentions or expectations upon which they are based will occur. By its nature, forward-looking information involves numerous assumptions, known and unknown risks and uncertainties, both general and specific, that contribute to the possibility that the predictions, forecasts, projections and other forward-looking statements will not occur. Forward-looking statements in this Annual Information Form include, but are not limited to, statements with respect to:

- capital expenditure programs and future capital requirements and the timing and method of financing thereof;
- the Corporation’s exploration and development activities;
- drilling inventory, drilling plans and timing of drilling, re-completion and tie-in of wells;
- the production from Kelt’s assets;
- results of various projects of Kelt;
- estimated abandonment and reclamation costs;
- the Corporation’s access to adequate pipeline capacity and third-party infrastructure;
- growth expectations within Kelt;
- the performance and characteristics of Kelt’s oil and natural gas properties;
- the quantity and quality of the Corporation’s oil and natural gas reserves;
- timing of development of undeveloped reserves;
- the tax horizon and taxability of Kelt;
- supply and demand for oil, natural gas liquids and natural gas;
- Kelt’s acquisition strategy, the criteria to be considered in connection therewith and the benefits to be derived therefrom;
- realization of the anticipated benefits of acquisitions and dispositions;
- commodity prices and costs;
- the dividend policy of Kelt;
- Kelt’s hedging activities;
- industry conditions pertaining to the oil and gas industry; and

- treatment under government regulation and taxation regimes.

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

- future crude oil, natural gas and NGL prices and commodity prices generally;
- future exchange rates;
- the ability of Kelt to obtain qualified staff, drilling and related equipment in a timely and cost-efficient manner to meet its needs;
- the timing and amount of capital expenditures;
- future operating costs and future cash flow;
- future capital expenditures to be made by the Corporation;
- future sources of funding for the Corporation's capital program;
- the Corporation's future debt levels;
- oil, natural gas and NGL production levels;
- prevailing weather conditions;
- general economic and financial market conditions;
- government regulation in the areas of taxation, royalty rates and environmental protection;
- production of new and existing wells and the timing of new wells coming on-stream;
- the performance characteristics of oil and natural gas properties;
- the size of Kelt's oil, natural gas and NGL reserves and the recoverability of its reserves;
- the ability to raise capital and to continually add to reserves through exploration and development;
- the success of exploration and development activities;
- the Corporation's ability to market production of oil and natural gas successfully to customers;
- the applicability of technologies for recovery and production of the Corporation's reserves;
- the geography of the areas in which the Corporation is conducting exploration and development activities; and
- the impact of competition on the Corporation.

Although Kelt believes that the expectations reflected in the forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. Kelt cannot guarantee future results, levels of activity, performance, or achievements. Moreover, neither Kelt nor any other person assumes responsibility for the outcome of the forward-looking statements. There are many risks and other factors beyond Kelt's control which could cause results to differ materially from those expressed in the forward-looking statements contained in this Annual Information Form. These risks and other factors include, but are not limited to:

- general economic conditions in Canada, the United States and globally including reduced availability of debt and equity financing generally;
- industry conditions, including fluctuations in the price of oil, natural gas liquids and natural gas;
- liabilities inherent in oil and natural gas operations;
- governmental regulation of the oil and gas industry, including environmental regulation;
- fluctuation in foreign exchange or interest rates;
- geological, technical, drilling and processing problems and other difficulties in producing reserves;
- unanticipated operating events which can reduce production or cause production to be shut in or delayed;
- failure to realize anticipated benefits of acquisitions and dispositions;
- failure to obtain industry partner and other third party consents and approvals, when required;
- stock market volatility and market valuations;
- competition for, among other things, capital, acquisitions or reserves, undeveloped land and skilled personnel;
- competition for and inability to retain drilling rigs and other services;
- right to surface access;
- the need to obtain required approvals from regulatory authorities; and
- the other factors considered under "*Risk Factors*" in this Annual Information Form.

These factors should not be considered as exhaustive. Statements relating to “reserves” or “resources” are by their nature forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the resources and reserves described can be profitably produced in the future.

The above summary of assumptions and risks related to forward-looking information has been provided in this Annual Information Form in order to provide readers with a more complete perspective on Kelt’s future operations. Readers are cautioned that this information may not be appropriate for other purposes.

The forward-looking statements contained in this Annual Information Form are expressly qualified by this cautionary statement. Kelt is not under any duty to update or revise any of the forward-looking statements except as expressly required by applicable securities laws.

CORPORATE STRUCTURE

Name, Address and Incorporation

The Corporation was incorporated under the ABCA on October 11, 2012 as “1705972 Alberta Ltd.” On October 19, 2012, Articles of Amendment were filed to change the name of the company to “Kelt Exploration Ltd.” On November 7, 2012, Kelt filed Articles of Amendment to remove the private company restrictions on share transfers and to amend the minimum number of directors to three (3).

Kelt Exploration (LNG) Ltd. (formerly, Artek Exploration Ltd.), a corporation incorporated under the ABCA, is a wholly-owned subsidiary of the Corporation. Kelt does not have any other subsidiaries.

The head office of Kelt is located at Suite 300, 311 – 6th Avenue S.W., Calgary, Alberta T2P 3H2 and its registered office is located at Suite 1900, 520 – 3rd Avenue S.W., Calgary, Alberta T2P 0R3.

GENERAL DEVELOPMENT OF THE BUSINESS

Overview

Kelt is an oil and gas company based in Calgary, Alberta, focused on the exploration, development and production of crude oil and natural gas resources, primarily in northwestern Alberta and northeastern British Columbia. Kelt’s land holdings are located in two core areas, namely: (a) Grande Prairie (including Pouce Coupe, Progress, La Glace and Pipestone/Wembley), Alberta; and (b) Fort St. John (including Inga/Fireweed), British Columbia. See “*Description of the Business*” and “*Statement of Reserves Data and Other Oil and Gas Information*”.

History of Kelt

2012

Kelt was incorporated on October 11, 2012 for the purposes of participating in the Arrangement and completing the Arrangement Acquisition.

2013

The Arrangement and the Arrangement Acquisition

On February 26, 2013, pursuant to the Arrangement, the Purchaser acquired all of the issued and outstanding Celtic Shares, including the Celtic Shares issued upon the conversion of Celtic Debentures as described below, for cash consideration of \$24.50 per Celtic Share (the “**Cash Consideration**”). In addition to the Cash Consideration, each Celtic Shareholder received one-half (1/2) of one Common Share of Kelt for each Celtic Share held (the “**Share Consideration**”).

Pursuant to the Arrangement, the Celtic Debentures were converted into that number of Celtic Shares that Celtic Debentureholders would have been entitled to receive upon the conversion of Celtic Debentures in accordance with their terms immediately following the effective time of the Arrangement. The Celtic Debentureholders then received the Cash Consideration and the Share Consideration for each Celtic Share issued upon such conversion. Celtic Debentureholders also received a cash payment of approximately \$20.56 for each \$1,000 principal amount of Celtic Debentures comprised of: (i) accrued and unpaid interest on the Celtic Debentures to, but excluding, February 26, 2013; and (ii) an amount equal to the amount of interest that would otherwise be payable thereon from and including February 26, 2013 to, but excluding, March 29, 2013.

In addition, pursuant to the Arrangement, the transactions contemplated by the Asset Conveyance Agreement became effective and pursuant thereto, Celtic assigned and transferred to Kelt all of Celtic’s right, title, estate and interest in and to the petroleum, natural gas and related hydrocarbon rights and related personal property interests within, upon or under the lands and leases in the following properties, namely, a natural gas property located at Grande Cache, Alberta, a liquids rich natural gas property located at Inga, British Columbia and an oil prospect located at Karr, Alberta, (collectively, the “**Arrangement Assets**”).

As consideration for the Arrangement Assets, Kelt issued to Celtic that number of Common Shares equal to one-half (1/2) of the number of issued and outstanding Celtic Shares (including Celtic Shares issued to former Celtic Debentureholders), which Common Shares were ultimately distributed to former Celtic Shareholders as described above, all in accordance with the terms of the Arrangement.

Developments Subsequent to the Arrangement and the Arrangement Acquisition

Immediately following the completion of the Arrangement and the Arrangement Acquisition, Kelt completed a non-brokered private placement whereby it issued an aggregate of 6,000,000 Common Shares at a subscription price of \$2.32 per Common Share, which was equal to the estimated net asset value of Kelt on a per share basis immediately following completion of the Arrangement, resulting in aggregate gross proceeds of \$13.92 million to Kelt.

Immediately following the completion of the Arrangement and the Arrangement Acquisition, Kelt completed the establishment of a revolving operating demand loan credit facility in the amount of \$40.0 million.

On March 1, 2013, the Common Shares commenced trading on the TSX under the stock symbol “KEL”.

On March 7, 2013, Kelt announced that the Board of Directors had approved a 2013 capital expenditure budget of \$52.0 million. In addition, and in connection with the Arrangement, approximately \$25.0 million was incurred by Kelt with respect to capital projects, including land acquisitions, prior to the completion of the Arrangement on February 26, 2013.

On April 5, 2013, Kelt completed a brokered and non-brokered equity financing for gross aggregate proceeds of \$94.35 million. Pursuant to an agreement with a syndicate of underwriters, the Corporation issued 11,000,000 Common Shares at a price of \$5.55 per Common Share, on a “bought deal” private placement basis, resulting in gross proceeds to the Corporation of \$61.05 million. In conjunction with the brokered private placement, Kelt issued an additional 6,000,000 Common Shares at a price of \$5.55 per Common Share to certain directors, officers and employees of the Corporation, on a non-brokered private placement basis, resulting in additional gross proceeds of \$33.3 million. Net proceeds from these private placements were initially used to pay down existing indebtedness, and thereafter to fund ongoing exploration and development activities, potential asset acquisitions and for general working capital purposes.

On August 9, 2013, Kelt completed the acquisition of certain natural gas and NGL assets located in the Fireweed area, British Columbia, adjacent to Kelt’s property located at Inga, in northeastern British Columbia (the “**Fireweed Acquisition**”). The effective date of the Fireweed Acquisition was April 1, 2013 and the purchase price, before closing adjustments, was \$15.5 million. Also included among the assets acquired was an interest in a compression and dehydration facility with approximately 16 MMcf/d of gross natural gas capacity and 25 kilometers of pipeline.

On August 27, 2013, Kelt completed a brokered equity financing for gross aggregate proceeds of \$111.6 million. Pursuant to an agreement with a syndicate of underwriters, the Corporation issued: (i) 11,500,000 Common Shares (which included the exercise in full of an over-allotment option to purchase 1,500,000 Common Shares) at a price of \$8.00 per Common Share, on a “bought deal” private placement basis; and (ii) 2,000,000 Common Shares issued on a “flow-through” basis pursuant to the *Income Tax Act* (Canada) at a price of \$9.80 per “flow-through” Common Share, on a guaranteed agency basis. Net proceeds from these private placements were used to fund capital expenditures and for general working capital purposes.

On December 3, 2013, Kelt completed a brokered equity financing for aggregate gross proceeds of \$101.06 million. Pursuant to an agreement with a syndicate of underwriters, the Corporation issued 10,000,000 subscription receipts of Kelt (“**Subscription Receipts**”) at a price of \$8.15 per Subscription Receipt, on a “bought deal” private placement basis, for gross proceeds of \$81.5 million. In conjunction with the brokered private placement, Kelt issued an additional 2,400,000 Subscription Receipts at a price of \$8.15 per Subscription Receipt to certain directors and officers of the Corporation, on a non-brokered private placement basis, resulting in additional gross proceeds of \$19.56 million. The Subscription Receipts entitled the holders to acquire Common Shares, on a one-for-one basis, for no additional consideration, upon the Corporation being in a position to close the closing of the Pouce Coupe/Spirit River Acquisition, other than the payment of the purchase price therefor.

On December 20, 2013, Kelt completed the acquisition of certain crude oil and natural gas assets located at Pouce Coupe/Spirit River, Alberta, in close proximity to its core producing areas at Grande Cache and Karr in west central

Alberta (the “**Pouce Coupe/Spirit River Acquisition**”). The effective date of the Pouce Coupe/Spirit River Acquisition was October 1, 2013 and the purchase price, before closing adjustments, was \$191.96 million, which was financed in part from the proceeds from the private placement of Subscription Receipts. Also included among the assets acquired was a major infrastructure component with interest in major oil and gas facilities including a 20.2% interest in a 140 MMcf/d gas processing plant, varying ownership interests in gas compressors, oil batteries, in an extensive network of oil and gas gathering pipelines and an established field office located in Grande Prairie, Alberta.

Immediately following the completion of the Pouce Coupe/Spirit River Acquisition, Kelt amended its revolving operating demand loan credit facility to increase the amount thereof to \$100.0 million.

2014

On February 10, 2014, Kelt completed the disposition of certain non-core and non-operated assets that were included in the Pouce Coupe/Spirit River Acquisition. Kelt received proceeds of \$20.0 million, before closing adjustments. Proved reserves, as at December 31, 2013, for the subject disposed assets were 500,500 bbls and proved plus probable reserves were 635,100 bbls. Kelt had not assigned any future development capital or future drilling locations to these assets.

On March 25, 2014 Kelt completed a brokered and non-brokered equity financing for gross aggregate proceeds of \$146,786,250. Pursuant to an agreement with a syndicate of underwriters, the Corporation issued: (i) 9,775,000 Common Shares (which included the exercise in full of an over-allotment option to purchase 1,275,000 Common Shares) at a price of \$11.60 per Common Share, on a “bought-deal” private placement; and (ii) 1,530,000 Common Shares issued on a “flow-through” basis in respect of Canadian development expenses pursuant to the *Income Tax Act* (Canada) at a price of \$12.75 per “flow-through” Common Share, on a guaranteed agency basis. In conjunction with the brokered private placement, Kelt issued an additional 1,105,000 Common Shares on a “flow-through” basis in respect of Canadian development expenses pursuant to the *Income Tax Act* (Canada) at a price of \$12.75 per “flow-through” Common Share, on a non-brokered private placement basis, to certain officers, directors and employees of the Corporation. Net proceeds from these private placements were used to partially finance Kelt’s 2014 capital expenditure program and for general working capital purposes.

On May 6, 2014, Kelt entered into a syndicated credit agreement (the “**Syndicated Credit Agreement**”) with a syndicate of lenders and established credit facilities in the aggregate amount of \$100.0 million.

On July 2, 2014, Kelt completed the acquisition of a private Canadian oil and gas company (“**PrivateCo**”) with crude oil and natural gas assets located at Valhalla/La Glace, adjacent to Kelt’s core producing areas at Pouce Coupe and Spirit River in west central Alberta (the “**PrivateCo Acquisition**”). The consideration paid by Kelt, before adjustments, was \$165.0 million, consisting of \$107.0 million in cash (including proceeds to shareholders of PrivateCo, as well as repayment of all outstanding debt of PrivateCo) and the issuance of 4,270,956 Common Shares with an aggregate value of \$58.0 million, based on the five day volume weighted average price of Kelt’s Common Shares that traded on the TSX from June 9 to June 13, 2014 of \$13.58. Immediately following the completion of the PrivateCo Acquisition, all of the property, assets and liabilities of PrivateCo were assigned to Kelt and PrivateCo was subsequently dissolved.

On November 17, 2014, Kelt announced that the Board of Directors had approved a 2015 capital expenditure budget of \$215.0 million.

On November 28, 2014, Kelt entered into an amendment to the Syndicated Credit Agreement to increase the amount of the credit facilities thereunder to the aggregate amount of \$235.0 million.

On December 18, 2014, Kelt completed the acquisition of certain natural gas and NGL assets located in the Stoddart area of British Columbia, adjacent to Kelt’s properties located at Inga and Fireweed, in northeastern British Columbia (the “**Stoddart Acquisition**”). The effective date of the Stoddart Acquisition was October 1, 2014 and the purchase price, before closing adjustments, was \$10.35 million. Also included among the assets acquired were interests in compression facilities and significant pipeline infrastructure.

2015

On January 20, 2015, Kelt announced that, in view of the precipitous decline in global oil prices, its capital expenditure budget for 2015 was reduced from \$215.0 million to \$152.0 million.

On February 23, 2015, Kelt announced that, excluding the Artek Arrangement, it had further reduced its capital expenditure budget by \$2.0 million to \$150.0 million.

On February 27, 2015, Kelt completed the first tranche of a non-brokered private placement of 1,000,000 Common Shares, on March 6, 2015, Kelt completed the second tranche of the non-brokered private placement of 2,300,000 Common Shares and on March 16, 2015 Kelt completed the third tranche of the non-brokered private placement of 581,400 Common Shares, all issued on a “flow-through” basis in respect of Canadian development expenses pursuant to the *Income Tax Act* (Canada) at a price of \$8.60 per flow-through Common Share, for aggregate gross proceeds of \$33,380,040. Proceeds from the foregoing non-brokered private placement were used to partially finance the Corporation’s drilling and completion expenditures during the remainder of 2015.

On April 16, 2015, Kelt completed the Artek Arrangement. Pursuant to the Artek Arrangement, Artek became a wholly-owned subsidiary of Kelt.

On April 16, 2015, immediately following the completion of the Artek Arrangement, a name change was effected to change the name of Artek Exploration Ltd. to Kelt Exploration (LNG) Ltd. (“**Kelt LNG**”), and Kelt transferred all of its British Columbia assets to Kelt LNG and at the same time, Kelt LNG transferred all of its Alberta assets to Kelt.

On April 16, 2015, immediately following the completion of the Artek Arrangement, Kelt amended the Syndicated Credit Agreement by entering into an Amended and Restated Credit Agreement (the “**Amended and Restated Credit Agreement**”) which increased the amount of Kelt’s credit facilities to \$300.0 million.

On June 15, 2015, the Corporation announced that it had expanded its capital expenditure budget to \$497.0 million for 2015, up \$40.0 million from \$457.0 million and that excluding the Artek Arrangement, forecasted 2015 capital expenditures were increased from \$150.0 million to \$185.0 million.

On July 7, 2015, Kelt completed an equity financing by way of a short form prospectus, including the exercise in full of the over-allotment option granted in connection therewith, of 9,775,000 Common Shares at a price of \$8.85 per share for gross proceeds of \$86,508,250.

On July 7, 2015, Kelt also completed a non-brokered private placement of 400,000 Common Shares at a price of \$8.85 per share for gross proceeds of \$3,540,000. The aggregate net proceeds from the short form prospectus offering and the non-brokered private placement were used initially to temporarily reduce indebtedness under Kelt’s credit facilities, which were subsequently redrawn and applied to partially fund Kelt’s 2015 capital expenditures programs and for general working capital proposes.

On November 10, 2015, Kelt announced that the Board of Directors had approved a 2016 capital expenditure budget of \$110.0 million.

On November 13, 2015, Kelt entered into an amendment to the Amended and Restated Credit Agreement to reduce the amount of the credit facilities thereunder by \$25.0 million to the aggregate amount of \$275.0 million, with additional funds available up to the total credit facility commitment of \$300.0 million subject to approval of the lending syndicate.

2016

On February 10, 2016, Kelt announced that, due to market instability and volatile commodity prices, it had reduced its capital expenditure budget from \$110.0 million to \$65.0 million.

On April 7, 2016, Kelt completed a private placement of 4,700,000 Common Shares issued on a “flow-through” basis in respect of Canadian development expenses pursuant to the *Income Tax Act* (Canada) at a price of \$4.70 per Common Share for gross proceeds of \$22.1 million. Proceeds from the foregoing private placement were used to partially finance Kelt’s drilling and completion expenditures during the remainder of 2016.

On April 28, 2016, the Corporation completed the purchase of certain assets in its core area at Progress, Alberta for cash consideration in the amount of \$18.8 million, before customary closing adjustments which included approximately 600 BOE per day of production (60% light oil), 4,135 net acres of land and various infrastructure.

On May 3, 2016, Kelt completed a convertible debenture financing by way of a short form prospectus on a bought deal basis by completing the sale of \$75.0 million principal amount of 5.0% convertible unsecured subordinated debentures (the “**Kelt Debentures**”) at a price of \$1,000 per Kelt Debenture. On May 3, 2015, Kelt also completed a private placement offering to certain directors, officers and employees of the Corporation, along with certain other subscribers, on a non-brokered basis, of an additional \$15.0 million principal amount of Kelt Debentures at a price of \$1,000 per Kelt Debenture. Net proceeds from the Kelt Debenture offerings was initially used to pay down existing bank credit facilities and thereafter, for general corporate and working capital purposes.

The Kelt Debentures will mature and be repayable on May 31, 2021 (the “**Maturity Date**”) and will accrue interest at the rate of 5.0% per annum payable semi-annually in arrears on May 31st and November 30th of each year (each an “**Interest Payment Date**”), commencing on November 30, 2016. At the holder’s option, the Kelt Debentures may be converted into Common Shares at any time prior to the close of business on the earlier of the business day immediately preceding (i) the Maturity Date, (ii) if called for redemption, the date fixed for redemption by the Corporation, or (iii) if called for repurchase in the event of a change of control, the payment date, at a conversion price of \$5.50 per share, subject to adjustment in certain events (the “**Conversion Price**”). This represents a conversion rate of approximately 181.8182 Common Shares for each \$1,000 principal amount of Kelt Debentures, subject to certain anti-dilution provisions. Holders who convert their Kelt Debentures will receive, in addition to the applicable number of Common Shares, accrued and unpaid interest in respect thereof for the period up to, but excluding, the date of conversion from, and including, the most recent Interest Payment Date.

The Kelt Debentures are direct, subordinated, unsecured obligations of the Corporation, subordinated to any existing and future senior indebtedness of the Corporation and ranking equally with one another and with all other existing and future subordinated unsecured indebtedness of the Corporation to the extent subordinated on the same terms.

The Kelt Debentures may not be redeemed by the Corporation prior to May 31, 2019 except in certain circumstances following a change of control. On and after May 31, 2019 and prior to May 31, 2020, the Kelt Debentures may be redeemed by the Corporation, in whole or in part, from time to time, on not more than 60 days and not less than 40 days prior notice at a redemption price equal to their principal amount plus accrued and unpaid interest, if any, up to but excluding the date set for redemption, provided that the volume weighted average trading price of the Common Shares on the TSX for the 20 consecutive trading days ending five trading days prior to the date on which notice of redemption is provided is at least 125% of the Conversion Price. On or after May 31, 2020 and prior to the Maturity Date, the Kelt Debentures may be redeemed by the Corporation, in whole or in part, from time to time, on not more than 60 days and not less than 40 days prior notice at a redemption price equal to their principal amount plus accrued and unpaid interest, if any, up to but excluding the date set for redemption.

The Kelt Debentures were listed and posted for trading on the TSX under the symbol “KEL.DB” at the open of markets on May 3, 2016.

On May 11, 2016, Kelt announced that, following its asset acquisition at Progress, Alberta, it had increased its 2016 capital expenditure budget from \$65.0 million to \$83.0 million.

On May 31, 2016, Kelt announced that its Amended and Restated Credit Facility, as amended, had been further amended to provide for certain amendments to its credit facility and that its borrowing base had been re-determined at \$185.0 million.

On August 10, 2016, Kelt announced that it had increased its 2016 capital expenditure budget from \$83.0 million to \$87.0 million.

On August 23, 2016, Kelt completed a non-brokered private placement of 384,600 Common Shares, issued on a “flow-through” share basis in respect of Canadian exploration expenses pursuant to the *Income Tax Act* (Canada) at a price of \$6.50 per Common Share, for gross proceeds of \$2.5 million. Proceeds from the foregoing private placement were used to partially finance Kelt’s drilling and completion expenditures during the remainder of 2016.

On November 2, 2016, Kelt completed a non-brokered private placement of 1,000,000 Common Shares issued on a “flow-through” share basis in respect of Canadian development expenses pursuant to the *Income Tax Act* (Canada) at

a price of \$7.10 per Common Share, for gross proceeds of \$7.1 million. Proceeds from the foregoing private placement were used to partially finance Kelt's drilling and completion expenditures during the remainder of 2016.

On November 10, 2016, Kelt announced that the Board of Directors had approved a 2017 capital expenditure budget of \$97.0 million.

Activity During Current Fiscal Year

On January 4, 2017, Kelt announced the Karr Disposition (as defined below) and that the Board of Directors had approved an increase in the 2017 capital expenditure budget to \$144.6 million. A portion of the increase in capital spending is expected to be used for facilities, whereby Kelt expects to increase both compression and pipeline gathering capacity in its core producing areas to accommodate production additions. After giving effect to the Karr Disposition, net capital expenditures in 2017 are expected to be approximately \$42.0 million.

On January 18, 2017, Kelt completed the disposition of oil and gas assets located in the Karr area of Alberta ("**Karr Disposition**"). The Karr Disposition had an effective date of January 1, 2017. Kelt received gross proceeds, prior to adjustments at closing and following the waiver of certain preferential rights, in the amount of \$100.0 million. The Corporation's syndicate of lenders confirmed that the authorized borrowing amount available under the Amended and Restated Credit Facility, as amended, remained unchanged at \$185.0 million.

Significant Acquisitions

Kelt has not completed any "significant acquisitions" (as such term is defined in NI 51-102) during the financial year ended December 31, 2016.

DESCRIPTION OF THE BUSINESS

General Description of the Business

Kelt is an oil and gas company based in Calgary, Alberta, focused on the exploration, development and production of crude oil and natural gas resources, primarily in northwestern Alberta and northeastern British Columbia. Kelt's land holdings are located in two core areas, namely: (a) Grande Prairie (including Pouce Coupe, Progress, La Glace and Pipestone/Wembley), Alberta; and (b) Fort St. John (including Inga/Fireweed), British Columbia.

Kelt was incorporated for the purposes of participating in the Arrangement and completing the Arrangement Acquisition and prior to February 26, 2013, had not carried on any active business other than in connection with the Arrangement and related matters. Since the completion of the Arrangement and the Arrangement Acquisition on February 26, 2013, Kelt has carried on the business of the exploration for, and the development and production of, oil and natural gas.

Stated Business Objective

The business plan of Kelt is to create sustainable and profitable growth as a participant in the oil and gas industry in Canada. Kelt seeks to identify and acquire strategic oil and gas properties where it believes further exploitation, development and exploration opportunities exist. In addition, Kelt has implemented a full cycle exploration program, resulting in exploration and development drilling based on opportunities generated internally.

Kelt pursues exploration plays that have low, medium and high risk and multi-zone hydrocarbon potential and strives to maintain a balance between exploration, exploitation and development drilling for oil and gas reserves, although management of Kelt also considers asset and corporate acquisition opportunities that meet its business parameters. While Kelt believes that it has the skills and resources necessary to achieve its stated objectives, participation in the exploration for and development of oil and gas has a number of inherent risks. See "*Risk Factors*" in this Annual Information Form.

Marketing

Kelt's crude oil, natural gas and NGL production is sold primarily through marketing companies at current market prices. Crude oil contracts are generally month to month and cancellable on 30 days' notice, NGL contracts are

generally for a period of up to one year and are cancellable on 90 days' notice and natural gas contracts are generally for one year.

Cyclical and Seasonal Nature of Industry

Kelt's operational results and financial condition are dependent on the prices received for oil and natural gas production. Oil and natural gas prices have fluctuated widely during recent years and, over the past year, have experienced a sharp decline in the early months of 2016, with a modest recovery in the second half of the year. Such prices are determined by supply and demand factors, including weather and general economic conditions, as well as conditions in other oil and natural gas regions. Any decline in oil and natural gas prices could have an adverse effect on the financial condition of Kelt. See "*Risk Factors – Prices, Markets and Marketing of Crude Oil and Natural Gas*" in this Annual Information Form.

The production of oil and natural gas is dependent on access to areas where development of reserves is to be conducted. Seasonal weather variations, including freeze-up and break-up, affect access in certain circumstances. See "*Risk Factors – Seasonality*" in this Annual Information Form.

Employees

As at the date of this Annual Information Form, Kelt has 46 full-time employees and 4 part-time employee located at its head office. In addition, the Corporation has 26 full time employees located at various field operational sites. To continue with the development of its assets, Kelt may require additional experienced employees and third-party consultants and contractors. See "*Risk Factors – Reliance on Key Personnel*" in this Annual Information Form.

Specialized Skill and Knowledge

Kelt believes its success is dependent on the performance of its management and key employees, many of whom have specialized knowledge and skills relating to oil and gas operations. Kelt believes that it has adequate personnel with the specialized skills required to successfully carry out its operations. See "*Risk Factors – Reliance on Key Personnel*" in this Annual Information Form.

Competitive Conditions

The oil and gas industry is highly competitive. Kelt actively competes for reserve acquisitions, exploration leases, licences and concessions and skilled industry personnel with a substantial number of other oil and gas entities, many of which have significantly greater financial resources, staff and facilities than Kelt. Kelt's competitors include integrated oil and natural gas companies and numerous other independent oil and natural gas companies and individual producers and operators. Certain of Kelt's customers and potential customers may themselves explore for oil and natural gas and the results of such exploration efforts could affect Kelt's ability to sell or supply oil or gas to these customers in the future. Kelt's ability to successfully bid on and acquire additional property rights, to discover reserves, to participate in drilling opportunities and to identify and enter into commercial arrangements with customers is dependent upon developing and maintaining close working relationships with its future industry partners and joint operators and its ability to select and evaluate suitable properties and to consummate transactions in a highly competitive environment. 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. See "*Risk Factors – Competition*" in this Annual Information Form.

Environmental Protection

The oil and gas industry is subject to environmental regulations pursuant to applicable legislation. Such legislation provides for restrictions and prohibitions on release or emission of various substances produced in association with certain oil and gas industry operations, and requires that well and facility sites be abandoned and reclaimed to the satisfaction of environmental authorities. Kelt maintains an insurance program consistent with industry practice to protect against losses due to accidental destruction of assets, well blowouts, pollution and other operating accidents or disruptions. Kelt has established operational and emergency response procedures and safety and environmental programs to reduce potential loss exposure. No assurance can be given that the application of environmental laws to the business and operations of Kelt will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise adversely affect Kelt's financial condition, results of

operations or prospects. See “*Risk Factors – Environmental Risks*” and “*Industry Conditions – Environmental Regulation*” in this Annual Information Form.

Social and Environmental Policies

Kelt is committed to meeting industry standards in each jurisdiction in which it operates with respect to human rights, environment, health and safety policies. Management, employees and contractors are governed by and required to comply with Kelt’s environment, health and safety policy as well as all applicable federal, provincial and municipal legislation and regulations.

Kelt has established roles and responsibilities to facilitate effective management of its environment, health and safety policy throughout the organization. It is the primary responsibility of the managers, supervisors and other senior field staff of Kelt to oversee safe work practices and ensure that rules, regulations, policies and procedures are being followed.

Bankruptcy and Similar Procedures

There has been no bankruptcy, receivership or similar proceedings against Kelt, or any voluntary bankruptcy, receivership or similar proceedings by Kelt.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Petroleum and Natural Gas Reserves

Sproule, independent petroleum engineers of Calgary, Alberta, prepared the Sproule Report evaluating and auditing the proved and probable crude oil, natural gas and NGL reserves attributable to Kelt’s interest in 100% of its properties and the present value of estimated future cash flow from such reserves, based on forecast price and cost assumptions. All of Kelt’s reserves are in Canada, and, specifically, in Alberta and British Columbia. The reserves information was prepared and is presented in accordance with the requirements of NI 51-101.

In preparing the Sproule Report, Sproule obtained information from Kelt, which included land data, well information, geological information, reservoir studies, estimates of on-stream dates, contract information, current hydrocarbon product prices, operating cost data, capital budget forecasts, financial data, future operating plans and estimated abandonment and reclamation costs for Kelt’s dedicated facilities. Other engineering, geological or economic data required to conduct the evaluation and audit and upon which the Sproule Report is based, was obtained from public records, other operators and from Sproule’s non-confidential files. The extent and character of ownership and the accuracy of all factual data supplied for the independent evaluation, from all sources, was accepted by Sproule as represented.

Disclosure of Reserves Data

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 are numerous uncertainties inherent in estimating quantities of crude oil, NGL and natural gas reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth in this Annual Information Form are estimates only. The recovery and reserve estimates of the crude oil, NGL and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and NGL reserves may be greater than or less than the estimates provided herein. In general, estimates of economically recoverable crude 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 crude oil and natural 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, among others, estimates of the economically recoverable crude 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 may vary and such variations may be material. The actual production, revenues, taxes and development and operating expenditures with respect to the reserves associated with the Kelt’s assets may vary from the information presented herein and such variations could be material. See “*Risk Factors*” in this Annual Information Form.

The following tables, based on the Sproule Report, show the estimated share of Kelt's oil, natural gas and NGL reserves in its properties and the present value of estimated future net revenue for these reserves, after provision for Alberta gas cost allowance, using forecast price and cost assumptions. **All evaluations and audits of the present worth of estimated future net revenue in the Sproule Report are stated after provision for estimated future capital expenditures, both before and after income taxes, but prior to indirect costs, well abandonment and disconnect costs and surface lease reclamation costs or equipment salvage values and do not necessarily represent the fair market value of the reserves.**

Throughout the following summary tables differences may arise due to rounding.

In accordance with the requirements of NI 51-101, attached hereto are the following appendices:

- Appendix A: Report on Reserves Data by Independent Qualified Reserves Evaluator or Auditor in Form 51-101F2 containing certain information estimated using forecast prices and costs based on December 31, 2016 pricing assumptions
- Appendix B: Report of Management and Directors on Oil and Gas Disclosure in Form 51-101F3

Definitions used for reserve categories in the Sproule Report are attached as Appendix C hereto.

The following table summarizes Kelt's oil and gas reserves as of December 31, 2016 based on forecast price and cost assumptions.

SUMMARY OF OIL AND GAS RESERVES						
as of December 31, 2016						
FORECAST PRICES AND COSTS						
RESERVES						
	LIGHT CRUDE OIL AND MEDIUM CRUDE OIL		CONVENTIONAL NATURAL GAS ⁽¹⁾		NATURAL GAS LIQUIDS	
RESERVES CATEGORY	Gross (Mbbbl)	Net (Mbbbl)	Gross (MMcf)	Net (MMcf)	Gross (Mbbbl)	Net (Mbbbl)
PROVED						
Developed Producing	6,275.9	5,270.9	135,317	120,797	5,638.0	4,456.3
Developed Non-Producing	368.6	341.8	4,890	4,374	209.7	163.2
Undeveloped	6,137.8	5,018.1	281,384	241,915	19,297.5	16,302.3
TOTAL PROVED	12,782.4	10,630.8	421,592	367,084	25,145.2	20,921.8
PROBABLE	10,526.2	8,594.6	311,445	262,892	23,439.1	19,287.1
TOTAL PROVED PLUS PROBABLE	23,308.5	19,225.3	733,037	629,977	48,584.3	40,208.9

Note:

(1) Natural gas volumes include associated, non-associated and solution gas.

The following tables summarize the undiscounted value and the present value, discounted at 5%, 10%, 15% and 20%, of Kelt's estimated future net revenue based on forecast price and cost assumptions as of December 31, 2016.

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE as of December 31, 2016 ⁽¹⁾											
FORECAST PRICES AND COSTS											
RESERVES CATEGORY	BEFORE INCOME TAXES DISCOUNTED AT (%/year)					AFTER INCOME TAXES DISCOUNTED AT (%/year)					UNIT VALUE BEFORE INCOME TAX DISCOUNTED AT 10%/year
	0 (M\$)	5 (M\$)	10 (M\$)	15 (M\$)	20 (M\$)	0 (M\$)	5 (M\$)	10 (M\$)	15 (M\$)	20 (M\$)	\$/BOE
PROVED											
Developed Producing	623,758	503,989	422,806	365,764	323,831	623,758	503,989	422,806	365,764	323,831	14.16
Developed Non- Producing	20,904	16,837	13,640	11,203	9,327	20,904	16,837	13,640	11,203	9,327	11.05
Undeveloped	1,309,344	768,170	503,771	350,601	252,396	1,047,060	623,909	413,718	289,998	209,518	8.17
TOTAL PROVED	1,954,006	1,288,996	940,216	727,568	585,554	1,691,722	1,144,735	850,164	666,966	542,675	10.14
PROBABLE	1,954,885	1,170,501	790,474	575,712	440,863	1,430,552	854,901	574,378	416,397	317,798	11.03
TOTAL PROVED PLUS PROBABLE	3,908,891	2,459,498	1,730,690	1,303,280	1,026,417	3,122,274	1,999,636	1,424,542	1,083,363	860,473	10.53

Note:

- (1) Values reflect abandonment and reclamation costs for all existing wells assigned reserves and for all future locations assigned reserves in the Sproule Report as well as abandonment and reclamation costs for dedicated facilities required to produce the assigned reserves, in the aggregate amount of \$87.853 million (undiscounted) for total proved reserves and \$121.060 million (undiscounted) for total proved plus probable reserves.

TOTAL FUTURE NET REVENUE (UNDISCOUNTED) as of December 31, 2016								
FORECAST PRICES AND COSTS								
RESERVES CATEGORY	REVENUE (M\$)	ROYALTIES (M\$)	OPERATING COSTS (M\$)	DEVELOP- MENT COSTS (M\$)	ABANDON- MENT AND RECLAMA- TION COSTS (M\$)	FUTURE NET REVENUE BEFORE INCOME TAXES (M\$)	INCOME TAXES (M\$)	FUTURE NET REVENUE AFTER INCOME TAXES (M\$)
Proved Reserves	4,592,490	598,811	1,363,279	588,541	87,853	1,954,006	262,284	1,691,722
Proved Plus Probable Reserves	8,677,323	1,203,633	2,496,123	947,616	121,060	3,908,891	786,617	3,122,274

FUTURE NET REVENUE BY PRODUCTION TYPE as of December 31, 2016			
FORECAST PRICES AND COSTS			
RESERVES CATEGORY	PRODUCTION TYPE	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/Year) (M\$)	UNIT VALUE BEFORE INCOME TAXES (discounted at 10%/Year) (\$/BOE)
Proved Reserves	Light and Medium Crude Oil (including solution gas and associated by-products)	353,410	15.53
	Conventional Natural Gas (including associated by-products) ⁽¹⁾	586,807	8.39
	Total	940,216	
Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and associated by-products)	596,853	14.53
	Conventional Natural Gas (including associated by-products) ⁽¹⁾	1,133,837	9.19
	Total	1,730,690	

Note:

(1) Includes corporate capital gas cost allowance.

PRICING ASSUMPTIONS

Forecast Prices and Costs - December 31, 2016

Sproule employed the following pricing, exchange rate and inflation rate assumptions in estimating Kelt's reserves data using forecast prices and costs as of December 31, 2016.

FORECAST PRICES USED IN PREPARING RESERVES DATA							
Sproule Associates Limited							
Price Forecast							
Effective December 31, 2016							
	Light Oil		Heavy & Medium Oil		Natural Gas Liquids		
Year	WTI Cushing Oklahoma (\$US/Bbl)	Canadian Light Sweet Crude⁽¹⁾ 40° API (\$Cdn/Bbl)	Western Canada Select 20.5° API (\$Cdn/Bbl)	Hardisty Bow River 24.9° API (\$Cdn/Bbl)	Edmonton Propane (\$Cdn/Bbl)	Edmonton Butane (\$Cdn/Bbl)	Edmonton Pentanes Plus (\$Cdn/Bbl)
Historical							
2012	94.19	86.57	73.08	74.36	47.40	64.48	100.76
2013	97.98	93.27	74.93	76.16	38.37	69.88	105.48
2014	93.00	93.99	81.06	81.67	44.42	68.02	102.39
2015	48.80	57.45	44.83	45.35	6.17	36.81	61.45
2016	43.32	52.80	38.30	38.63	12.09	33.13	54.49
Forecast							
2017	55.00	65.58	53.12	53.77	22.74	47.60	67.95
2018	65.00	74.51	61.85	62.59	28.04	55.49	75.61
2019	70.00	78.24	64.94	65.72	30.64	57.65	78.82
2020	71.40	80.64	66.93	67.74	32.27	58.80	80.47
2021	72.83	82.25	68.27	69.09	33.95	59.98	82.15
2022	74.28	83.90	69.64	70.47	35.68	61.18	83.86
2023	75.77	85.58	71.03	71.88	37.46	62.40	85.61
2024	77.29	87.29	72.45	73.32	39.30	63.65	87.39
2025	78.83	89.03	73.90	74.79	41.19	64.92	89.21
2026	80.41	90.81	75.38	76.28	43.13	66.22	91.07
2027	82.02	92.63	76.88	77.81	45.14	67.54	92.96
Thereafter	Escalation rate of 2.0% thereafter						

Note:

(1) Edmonton Par prior to 2014.

Year	Natural Gas			Operating Cost Inflation Rate (%/Yr)	Exchange Rate (\$US/\$Cdn)
	Henry Hub Price (\$US/MMbtu)	Alberta AECO-C Spot (\$Cdn/MMbtu)	Alliance Pipeline (\$Cdn/MMbtu)		
Historical					
2012	2.79	2.43	1.67	1.0	1.001
2013	3.68	3.13	3.40	1.0	0.971
2014	4.28	4.50	6.46	2.0	0.905
2015	2.63	2.70	3.55	1.8	0.783
2016	2.55	2.18	3.27	1.2	0.755
Forecast					
2017	3.50	3.44	4.39	0.0	0.780
2018	3.50	3.27	4.17	2.0	0.820
2019	3.50	3.22	4.02	2.0	0.850
2020	4.00	3.91	4.61	2.0	0.850
2021	4.08	4.00	4.70	2.0	0.850
2022	4.16	4.10	4.80	2.0	0.850
2023	4.24	4.19	4.89	2.0	0.850
2024	4.33	4.29	4.99	2.0	0.850
2025	4.42	4.40	5.10	2.0	0.850
2026	4.50	4.50	5.20	2.0	0.850
2027	4.59	4.61	5.31	2.0	0.850
Thereafter	Escalation rate of 2.0% thereafter				

Kelt's weighted average realized sales prices for the year ended December 31, 2016 were \$47.84/Bbl for oil, \$18.28/Bbl for NGLs and \$2.69/Mcf for natural gas, before derivative financial instruments.

RECONCILIATION OF CHANGES IN RESERVES AND FUTURE NET REVENUE

Reserves Reconciliation

The following table sets forth a reconciliation of the total gross (before calculation of royalties and before consideration of the Corporation's royalty interests) proved, probable and proved plus probable reserves as at December 31, 2016 based on forecast price and cost assumptions.

FACTORS	LIGHT CRUDE OIL AND MEDIUM CRUDE OIL			NATURAL GAS LIQUIDS			CONVENTIONAL GAS ⁽¹⁾			COMBINED		
	Gross Proved (Mbbbl)	Gross Probable (Mbbbl)	Gross Proved Plus Probable (Mbbbl)	Gross Proved (Mbbbl)	Gross Probable (Mbbbl)	Gross Proved Plus Probable (Mbbbl)	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved Plus Probable (MMcf)	Gross Proved (MBOE)	Gross Probable (MBOE)	Gross Proved Plus Probable (MBOE)
December 31, 2015 ⁽²⁾	11,614.0	9,487.0	21,101.1	17,650.0	15,626.3	33,276.3	327,423	249,355	576,779	83,834.5	66,672.6	150,507.2
Extensions & Improved Recovery	1,505.2	3,275.0	4,780.2	5,123.5	2,936.0	8,059.5	88,308	61,461	149,769	21,346.5	16,454.6	37,801.1
Infill Drilling	894.5	77.7	972.2	704.2	(316.2)	388.0	10,578	(4,108)	6,470	3,361.6	(923.1)	2,438.5
Technical Revisions	(158.3)	(2,167.3)	(2,325.7)	3,578.1	5,429.0	9,007.1	27,931	6,719	34,649	8,075.2	4,381.2	12,456.3
Discoveries	0.0	0.0	0.0	0.0	0.0	0.0	0	0	0	0.0	0.0	0.0
Acquisitions	619.9	151.1	771.0	49.8	12.2	62.0	3,092	759	3,851	1,185.0	289.9	1,474.9
Dispositions	(84.2)	(31.5)	(115.7)	(17.4)	(6.1)	(23.5)	(178)	(61)	(239)	(131.3)	(47.7)	(179.0)
Economic Factors	(246.9)	(265.9)	(512.8)	(457.7)	(242.1)	(699.8)	(6,734)	(2,680)	(9,414)	(1,826.8)	(954.8)	(2,781.6)
Production	(1,361.8)	0.00	(1,361.8)	(1,485.3)	0.00	(1,485.3)	(28,828)	0	(28,828)	(7,651.8)	0.0	(7,651.8)
December 31, 2016	12,782.4	10,526.2	23,308.5	25,145.2	23,439.1	48,584.3	421,592	311,445	733,037	108,192.9	85,872.7	194,065.6

Notes:

- Natural gas volumes include solution gas, associated and non-associated gas.
- 6,463.1 Mbbbl of IP and 12,265.9 Mbbbl of 2P liquid volumes (Inga B.C. and Fireweed B.C. areas) were classified as oil at December 31, 2015 but are now called condensate (and included in the Natural Gas liquids volumes) at December 31, 2016. To make the reconciliation more meaningful these liquid volumes have been included in the Natural Gas liquids opening balance.

ADDITIONAL INFORMATION RELATING TO RESERVES DATA

Undeveloped Reserves

Undeveloped reserves are attributed by Sproule in accordance with 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 reserves and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Proved and probable undeveloped reserves have been assigned in accordance with engineering and geological practices as defined under NI 51-101. In general, undeveloped reserves associated with Kelt's assets are planned to be developed over the next two years.

In some cases, it will 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). For more information, see "Risk Factors" in this Annual Information Form.

Proved Undeveloped Reserves

The following table sets forth the proved undeveloped reserves, by product type, first attributed as reserves for the following financial periods and first attributed to Kelt's assets for the year ended December 31, 2016.

Year/Period	LIGHT CRUDE OIL AND MEDIUM CRUDE OIL		CONVENTIONAL NATURAL GAS ⁽²⁾		NATURAL GAS LIQUIDS	
	First Attributed (Mbbbl)	Cumulative at Year End ⁽¹⁾ (Mbbbl)	First Attributed (MMcf)	Cumulative at Year End ⁽¹⁾ (MMcf)	First Attributed (Mbbbl)	Cumulative at Year End ⁽¹⁾ (Mbbbl)
Aggregate prior to 2014	1,989.9	1,989.9	78,486	78,486	1,531.0	1,531.0
December 31, 2014	4,699.6	7,547.8	40,365	128,112	1,127.1	3,687.0
December 31, 2015	3,931.9	10,198.0	61,392	185,211	2,255.7	6,780.6
December 31, 2016	2,081.5	6,137.8	90,728	281,384	5,097.2	19,297.5

Notes:

- (1) Cumulative at year end is cumulative of previous year/period plus first attributed, less developed during the year/period.
- (2) Natural gas volumes include solution gas, associated and non-associated gas.

Sproule has assigned 72,332.7 MBOE of proved undeveloped reserves in the Sproule Report under forecast prices and costs, together with approximately \$582.2 million of associated undiscounted future capital expenditures. Proven undeveloped capital spending in the first two forecast years of the Sproule Report accounts for approximately \$288.9 million or 49.6%, of the total forecast.

Probable Undeveloped Reserves

The following table sets forth the probable undeveloped reserves, by product type, first attributed as reserves for the following financial periods and first attributed to Kelt's assets for the year ended December 31, 2016.

Year	LIGHT CRUDE OIL AND MEDIUM CRUDE OIL		CONVENTIONAL NATURAL GAS ⁽²⁾		NATURAL GAS LIQUIDS	
	First Attributed (Mbbl)	Cumulative at Year End ⁽¹⁾ (Mbbl)	First Attributed (MMcf)	Cumulative at Year End ⁽¹⁾ (MMcf)	First Attributed (Mbbl)	Cumulative at Year End ⁽¹⁾ (Mbbl)
Aggregate prior to 2014	3,615.0	3,615.0	70,622	70,622	1,970.3	1,970.3
December 31, 2014	2,691.0	4,949.5	50,282	105,478	1,346.5	3,337.1
December 31, 2015	6,148.6	11,078.6	99,234	188,469	3,556.4	7,770.7
December 31, 2016	3,863.3	7,698.6	76,957	256,953	5,291.8	20,682.8

Notes:

- (1) Cumulative at year end is cumulative of previous year/period plus first attributed, less developed during the year/period.
(2) Natural gas volumes include solution gas, associated and non-associated gas.

Sproule has assigned 71,206.9 MBOE of probable undeveloped reserves and has allocated future development capital of approximately \$352.7 million to all probable undeveloped reserves with 19.7% scheduled for the first two years.

Significant Factors or Uncertainties

The process of estimating reserves requires decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserve estimates contained herein are based on current production forecasts, commodity prices and economic conditions. Kelt's reserves are evaluated by Sproule, an independent engineering firm.

Estimates made are reviewed and revised, either upward or downward, as warranted by new information. Revisions are often required due to changes in well performance, commodity 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. Kelt's actual production, revenues, taxes, development and operating expenditures with respect to its reserves may vary from such estimates, and such variances could be material. See "Risk Factors – Reserves Estimates" in this Annual Information Form.

Future Development Costs

The following table sets forth development costs deducted in the estimation of the future net revenue attributable to the reserve categories noted below, using forecast prices and costs.

Year	Undiscounted Forecast Prices and Costs	
	Proved Reserves (M\$)	Proved Plus Probable Reserves (M\$)
2017	113,373.9	146,482.8
2018	181,655.7	224,006.4
2019	135,151.3	224,571.4
2020	135,984.9	230,728.9
2021	21,716.7	107,995.4
Remaining Years	658.3	13,830.9
Total Undiscounted	588,540.8	947,615.9

Kelt expects to fund the development costs of these reserves through a combination of the funds available from its credit facility, internally generated cash flow and the issuance of new equity and/or debt where and when it believes appropriate. The Corporation has established a \$144.6 million capital program to fund its exploration and development activities for 2017. The Corporation's capital program does not include any new acquisition opportunities, which would likely be financed through debt or equity financings, if necessary.

There can be no guarantee that funds will be available or that the Board of Directors will allocate funding to develop all of the reserves attributable in the Sproule Report. Failure to develop those reserves could have a negative impact on Kelt's future cash flow.

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

See "Risk Factors – Substantial Capital Requirements; Liquidity" and "– Reserve Estimates" in this Annual Information Form.

Other Oil and Gas Information

The following is a description of the Corporation's principal oil and gas properties, and a description of the Corporation's major plants, facilities and installations.

Oil and Gas Properties

Northwestern Alberta

Greater Grande Cache: As at February 27, 2017, the Corporation has interests in 136,480 gross (99,400 net) acres in this area which is located approximately 30 kilometres north of Grande Cache, Alberta. At Greater Grande Cache, the Corporation has a 30.0% working interest in the 25 MMcf/d Copton gas plant located at 11-25-59-9-W6M, a 7.0% working interest in the 135 MMcf/d Narraway gas plant located at 10-8-62-10-W6M, and interests in various compressors and gas gathering pipelines.

Grande Prairie (including Pouce Coupe, Spirit River, Progress, La Glace and Pipestone/Wembley): As at February 27, 2017, the Corporation has interests in 407,788 gross (260,552 net) acres in this area which is centered approximately 75 kilometres north west of Grande Prairie, Alberta. At Grande Prairie, the Corporation has a 20.251% working interest in the 140 MMcf/d Progress gas plant located at 1-1-078-10W6M and a 100% working interest in a compression facility located at 6-33-77-11-W6M.

Northeastern B.C.

Inga/Fireweed: As at February 27, 2017, the Corporation has interests in 209,977 gross (199,935 net) acres in this area which is centered approximately 60 kilometres north west of Fort St. John, British Columbia. At Inga, the Corporation has a 100% working interest in a 28 MMcf/d gas battery, dehydration and compressor station located at 15-3-88-23-W6M. At Fireweed, the Corporation has a 100% working interest in a 16 MMcf/d facility located at A-16-A/094-A-13.

Oak/Flatrock: As at February 27, 2017, the Corporation has interests in 136,690 gross (135,913 net) acres in this area which is located approximately 30 kilometres north east of Fort St. John, British Columbia.

Oil and Gas Wells

The following table sets forth the number and status of wells as at December 31, 2016 in which Kelt has an interest.

Location	PRODUCING				NON-PRODUCING				SERVICE WELLS	
	Oil		Natural Gas		Oil		Natural Gas		Gross	Net
	Gross ⁽¹⁾	Net ⁽²⁾	Gross	Net	Gross	Net	Gross	Net		
Alberta	304	170.2	314	123.2	102	56.6	177	85.8	65	22.4
British Columbia	31	30.8	120	110.2	11	9.6	25	18.8	4	3.2
TOTAL	335	201.0	434	233.4	113	66.2	202	104.6	69	25.6

Notes:

- (1) "Gross" wells means the number of wells in which Kelt has a working interest or a royalty interest that may be convertible to a working interest.
- (2) "Net" wells means the aggregate number of wells obtained by multiplying each gross well by Kelt's percentage working interest therein.

Properties with no Attributed Reserves

The following table sets forth the gross and net acres of unproved properties held by Kelt as at December 31, 2016 and the net area of unproved property for which Kelt expects its rights to explore, develop and exploit to expire during the next year.

UNPROVED PROPERTIES - UNDEVELOPED LAND				
(acres)				
LOCATION	Gross⁽¹⁾	Net⁽²⁾	Net Area to Expire by December 31 2017	
Alberta	447,185	346,785		14,730
British Columbia	321,160	300,985		7,402
TOTAL	768,345	647,770		22,132

Notes:

- (1) "Gross Acres" are the total acres in which Kelt has or had an interest.
- (2) "Net Acres" is the aggregate of the total acres in which Kelt has or had an interest multiplied by Kelt's working interest percentage held therein.

There are no costs or work commitments associated with Kelt's non-producing properties except for annual lease rental payments.

Significant Factors or Uncertainties Relevant to Properties with No Attributed Reserves

There are no significant economic factors and uncertainties which affect the anticipated development or production activities on certain of the Corporation's properties with no attributed reserves.

Forward Contracts

Kelt's operational results and financial condition are dependent upon the prices received for oil and natural gas production. Oil and natural gas prices have fluctuated widely in recent years. Such prices are primarily determined by economic and political factors. Supply and demand factors, as well as weather and conditions in other oil and natural gas regions of the world also impact prices. Any upward or downward movement in oil and natural gas prices could have an effect on Kelt's financial condition.

Kelt may use certain financial instruments to hedge its exposure to commodity price fluctuations on a portion of its crude oil and natural gas production. These hedging activities could expose Kelt to losses or gains. See "Risk Factors – Hedging" in this Annual Information Form.

Additional Information Concerning Abandonment and Reclamation Costs

Kelt 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. Kelt expects to incur abandonment and reclamation costs on 1,153 gross (630.7 net) wells, comprising currently producing, non-producing and service wells. As at December 31, 2016, the Corporation has estimated its share of the total abandonment and reclamation costs for its existing wells and facilities to be \$145.8 million undiscounted (approximately \$17.4 million discounted at 10%), of which Kelt expects to pay approximately \$1.5 million over the next three financial years.

Of the undiscounted future abandonment and reclamation costs to be incurred over the life of Kelt's proved plus probable reserves, approximately \$121.1 million 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.

Tax Horizon

At the end of 2016, Kelt had approximately \$975.4 million of tax pools available. It is expected, based upon current legislation, Kelt's 2017 planned capital expenditures and various other assumptions, that no cash income taxes are to

be paid by Kelt in the near future. A higher level of capital expenditures than those currently contemplated for 2016, or further additional acquisitions, could further extend the estimated tax horizon.

Income Taxes

Kelt files all required income tax returns and believes that it is in full compliance with the provisions of the *Income Tax Act* (Canada) and all other applicable provincial tax legislation. However, such returns are subject to reassessment by the applicable taxation authority. In the event of a successful reassessment of Kelt, whether by re-characterization of exploration and development expenditures or otherwise, such reassessment may have an impact on current and future taxes payable.

Income tax laws relating to the oil and natural gas industry, such as the treatment of resource taxation or dividends, may in the future be changed or interpreted in a manner that adversely affects Kelt. Furthermore, tax authorities having jurisdiction over Kelt may disagree with how Kelt calculates its income for tax purposes or could change administrative practices to the Corporation's detriment.

Costs Incurred

The following table summarizes Kelt's corporate and property acquisition costs, exploration costs and development costs (before property dispositions) incurred during the year ended December 31, 2016. 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.

Acquisitions and Capital Expenditures	
Nature of cost	Amount (M\$)
Corporate Acquisition Costs	
Proved	-
Unproved	-
Property Acquisition Costs	
Proved	18,538
Unproved	252
Exploration Costs	35,575
Development Costs	50,072
Total	104,437

Exploration and Development Activities

The following table sets forth the results of exploration and development activities on Kelt's assets during the year ended December 31, 2016:

Wells⁽¹⁾	Gross	Net
Development		
Gas	5	5.0
Oil	10	7.3
Exploratory		
Gas	-	-
Oil	-	-
Service	-	-
Total	15	12.3

Note:

(1) Based on Lahee Classification System.

During 2017, Kelt expects to drill wells in both of its two core operating areas, targeting liquids-rich natural gas at Inga/Fireweed, British Columbia, and natural gas and light oil at Grande Prairie, Alberta.

Production Estimates

The following table discloses, by product type, the volume of working interest share of production estimated for Kelt's assets before the deduction of royalties for the first year for gross proved reserves and gross probable reserves as reported in the Sproule Report effective December 31, 2016, based on forecast prices and costs.

Corporation	Light Crude Oil and Medium Crude Oil (Bbl/d)	Conventional Natural Gas (Mcf/d)	Natural Gas Liquids (Bbl/d)	Combined (BOE/d)
Proved				
Developed producing	3,017.5	63,643.8	3,007.7	16,632.5
Developed non-producing	144.4	43.8	1.1	152.8
Undeveloped	1,724.9	13,408.2	900.0	4,859.6
Total Proved	4,886.8	77,095.9	3,908.8	21,644.9
Probable	1,009.3	9,989.0	953.2	3,627.3
Total Proved Plus Probable	5,896.1	87,084.9	4,862.0	25,272.3

The Pouce Coupe property and the Inga/Fireweed property each account for 20% or more of the estimated production set forth in the immediately preceding tables. The following tables disclose by product type the volume of working interest share of production estimated for each of the properties before the deduction of royalties for the first year for gross proved reserves and gross probable reserves as reported in the Sproule Report effective December 31, 2016, based on forecast prices and costs.

The estimated average daily volume of production for the Pouce Coupe property as reported in the Sproule Report is as follows:

Pouce Coupe	Light Crude Oil and Medium Crude Oil (Bbl/d)	Conventional Natural Gas (Mcf/d)	Natural Gas Liquids (Bbl/d)	Combined (BOE/d)
Proved				
Developed producing	957.5	19,468.5	359.7	4,562.0
Developed non-producing	1.6	120.5	2.5	24.2
Undeveloped	531.5	6,945.2	125.2	1,814.2
Total Proved	1,490.7	26,534.2	487.4	6,400.5
Probable	611.2	3,802.7	68.8	1,313.8
Total Proved Plus Probable	2,101.9	30,337.0	556.2	7,714.2

The estimated average daily volume of production for the first year for the Inga/Fireweed property as reported in the Sproule Report is as follows:

Inga/Fireweed	Light Crude Oil and Medium Crude Oil (Bbl/d)	Conventional Natural Gas (Mcf/d)	Natural Gas Liquids (Bbl/d)	Combined (BOE/d)
Proved				
Developed producing	25.8	18,600.0	2,054.2	5,180.0
Developed non-producing	1.6	-2.7	-0.8	0.4
Undeveloped	0.00	1,830.1	536.4	841.5
Total Proved	27.4	20,427.4	2,589.9	6,021.8
Probable	1.1	3,301.4	810.1	1,361.5
Total Proved Plus Probable	28.5	23,728.8	3,400.0	7,383.3

Production History

The following table summarizes Kelt's average daily production before deduction of royalties, for the periods indicated:

Product	2016				
	Year	Q4	Q3	Q2	Q1
Light & Medium Crude Oil (Bbl/d)	3,720	3,608	3,510	3,561	4,208
NGLs (Bbl/d)	4,059	3,640	4,056	4,137	4,405
Conventional Natural Gas (Mcf/d)	78,765	74,870	77,559	74,715	87,970
Sulphur (Lt/d) ⁽¹⁾	24	21	30	35	12
Total (BOE/d)	20,947	19,762	20,542	20,208	23,295

Note:

(1) Sulphur volumes have been converted to oil equivalence at 0.6 Lt per BOE.

Netback History

The following table sets forth information respecting average net product prices received, royalties paid, production expenses and operating netbacks received by the Corporation in respect of the Corporation's production of crude oil and natural gas for the periods indicated.

Category	2016				
	Year	Q4	Q3	Q2	Q1
Selling prices, before financial instruments					
Oil (\$/Bbl) ⁽¹⁾	47.84	58.23	52.47	49.76	34.01
NGLs (\$/Bbl) ⁽²⁾	18.28	23.11	17.96	18.21	14.24
Gas (\$/Mcf) ⁽³⁾	2.69	3.62	2.88	1.97	2.33
Selling prices, after financial instruments					
Oil (\$/Bbl) ⁽¹⁾	47.84	58.23	52.47	49.76	34.01
NGLs (\$/Bbl) ⁽²⁾	18.28	23.11	17.96	18.21	14.24
Gas (\$/Mcf) ⁽³⁾	2.70	3.59	2.94	1.97	2.33
Royalties					
Oil (\$/Bbl) ⁽¹⁾	7.06	8.50	9.61	6.39	4.44
NGLs (\$/Bbl) ⁽²⁾	0.92	2.40	0.58	0.21	0.59
Gas (\$/Mcf) ⁽³⁾	0.07	0.14	0.08	0.01	0.04
Transportation and selling expenses					
Oil (\$/Bbl) ⁽¹⁾	2.42	3.18	2.98	2.00	1.73
NGLs (\$/Bbl) ⁽²⁾	0.46	0.57	0.40	0.43	0.44
Gas (\$/Mcf) ⁽³⁾	0.59	0.60	0.54	0.63	0.59
Production expenses⁽⁴⁾					
Oil (\$/Bbl) ⁽¹⁾	9.29	9.48	8.34	9.53	9.68
NGLs (\$/Bbl) ⁽²⁾	9.29	9.48	8.55	9.47	9.74
Gas (\$/Mcf) ⁽³⁾	1.55	1.58	1.41	1.41	1.76
Operating netbacks					
Oil (\$/Bbl) ⁽¹⁾	29.07	37.07	31.54	31.84	18.16
NGLs (\$/Bbl) ⁽²⁾	7.61	10.66	8.43	8.10	3.47
Gas (\$/Mcf) ⁽³⁾	0.49	1.27	0.91	(0.08)	(0.06)

Notes:

- (1) "Oil" includes crude oil and field condensate.
- (2) "NGLs" include pentane, butane, propane, and ethane.
- (3) "Gas" includes natural gas and sulphur.
- (4) Production expenses include mine lease and surface lease rentals, property taxes and expenses related to the operation and maintenance of wells, production facilities and gathering systems. Production expenses are allocated to oil, NGLs and natural gas pro rata based on BOE equivalent production volumes.

Production Volume by Field

The following table discloses for each important field, and in total, Kelt's production volumes for the financial year ended December 31, 2016 for each product type.

Field	Light Crude Oil and Medium Crude Oil (Bbl/d)	Natural Gas Liquids (Bbl/d)	Conventional Natural Gas (Mcf/d)	Sulphur (Lt/d)⁽¹⁾	Combined (BOE/d)	%
British Columbia	32	3,037	24,239	14	7,132	34%
Greater Grande Prairie	2,995	700	38,247	10	10,087	48%
Karr	522	292	5,181	-	1,678	8%
Grande Cache	57	26	11,045	-	1,924	9%
Other	115	3	52	-	126	1%
TOTAL	3,720	4,059	78,765	24	20,947	100%

Note:

(1) Sulphur volumes have been converted to oil equivalence at 0.6 Lt per BOE.

RISK FACTORS

The business of exploring for, developing and producing oil and natural gas reserves is inherently risky. The following information is a summary only of certain risk factors relating to the Corporation and should be read in conjunction with the detailed information appearing elsewhere in this Annual Information Form. Prospective investors should carefully consider the risk factors set out below and consider all other information contained in this Annual Information Form and in the Corporation's other public filings before making an investment decision. The risks set out below are not an exhaustive list, nor should be taken as a complete summary or description of all the risks associated with the Corporation's business and the oil and natural gas business generally.

Weakness in the Oil and Gas Industry

Recent market events and conditions, including global excess oil and natural gas supply, recent actions taken by the Organization of the Petroleum Exporting Countries ("OPEC") and non-OPEC member countries' decisions on production growth, slowing growth in emerging economies, market volatility and disruptions in Asia, and sovereign debt levels in various countries, have caused significant weakness and volatility in commodity prices. North American crude oil price differentials are also expected to continue to be volatile throughout 2017 which will have an impact on crude oil prices for Canadian producers. These events and conditions have caused a significant decrease in the valuation of oil and gas companies and a decrease in confidence in the oil and gas industry. These difficulties have been exacerbated in Canada by the recent changes in government at the federal level and, in the case of Alberta, at the provincial level and the resultant uncertainty surrounding regulatory, tax and royalty changes that may be implemented by the new governments. In addition, the inability to get the necessary approvals or other delays to build pipelines and other facilities to provide better access to markets for the oil and gas industry in western Canada has led to additional uncertainty and reduced confidence in the oil and gas industry in western Canada. Lower commodity prices may also affect the volume and value of the Corporation's reserves especially as certain reserves become uneconomic. In addition, lower commodity prices have reduced, and are anticipated to continue to reduce the Corporation's cash flow which could result in a reduced capital expenditure budget. As a result, 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. Any decrease in value of the Corporation's reserves may reduce the borrowing base under the Credit Facilities, which, depending on the level of the Corporation's indebtedness, could result in the Corporation having to repay a portion of its indebtedness. Given the current market conditions and the lack of confidence in the Canadian oil and gas industry, the Corporation may have difficulty raising additional funds in the future or if it is able to do it may be on unfavourable and highly dilutive terms.

Credit Facilities

The amount authorized under the Corporation's Amended and Restated Credit Agreement, as amended, is dependent on the borrowing base determined by its lenders. The lenders under the Amended and Restated Credit Agreement use

the Corporation's reserves, commodity prices, and other factors, to periodically determine the Corporation's borrowing base. There remains a substantial amount of uncertainty as to when and if commodity prices will recover. Continued depressed commodity prices or further reductions in commodity prices could result in a reduction to the Corporation's borrowing base, reducing the funds available to the Corporation under the Credit Facilities. This could result in the requirement to repay a portion, or all, of the Corporation's indebtedness.

Prices, Markets and Marketing of Crude Oil and Natural Gas

Oil and natural gas are commodities whose prices are determined based on world demand, supply and other factors, all of which are beyond the control of Kelt. World prices for oil and natural gas have fluctuated widely in recent years. Any material decline in prices will result in a reduction of net production revenue. Oil and natural gas prices have varied greatly over the last two years and are expected to remain volatile in the near future in response to a variety of factors beyond the Corporation's control, including: (i) global energy supply, production and policies, including the ability of OPEC to set and maintain production levels in order to influence prices for oil; (ii) political conditions, including the risk of hostilities in the Middle East and global terrorism; (iii) global and domestic economic conditions, including currency fluctuations; (iv) the level of consumer demand, including demand for different qualities and types of crude oil and liquids; (v) the production and storage levels of North American natural gas and crude oil and the supply and price of imported oil and liquefied natural gas; (vi) weather conditions; (vii) the proximity of reserves and resources to, and capacity of, transportation facilities and the availability of refining and fractionation capacity; (viii) the ability, considering regulation and market demand, to export oil and liquefied natural gas and NGLs from North America; (ix) the effect of world-wide energy conservation and greenhouse gas reduction measures and the price and availability of alternative fuels; and (x) government regulations. Certain wells or other projects may become uneconomic as a result of a decline in world oil prices and natural gas prices, leading to a reduction in the future volume of Kelt's oil and gas production. Kelt might also elect not to produce from certain wells at lower prices. All these factors could result in a material decrease in Kelt's future net production revenue, causing a reduction in its oil and gas acquisition and development activities. In addition, bank borrowings available to Kelt will be in part determined by the borrowing base of Kelt. A sustained material decline in prices from historical average prices could reduce Kelt's future borrowing base, therefore reducing the bank credit available to Kelt, and could require that a portion of any existing bank debt of Kelt be repaid.

In addition to establishing markets for its oil and natural gas, Kelt must also successfully market its oil and natural gas to prospective buyers. The marketability and price of oil and natural gas which may be acquired or discovered by Kelt will be affected by numerous factors beyond its control. Kelt will be affected by the differential between the price paid by refiners for light quality oil and the grades of oil produced by Kelt. The ability of Kelt to market natural gas may depend upon its ability to acquire space on pipelines which deliver natural gas to commercial markets. Kelt will also likely be affected by deliverability uncertainties related to the proximity of its reserves to pipelines and processing facilities and related to operational problems with such pipelines and facilities and extensive government regulation relating to price, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and the management of other aspects of the oil and natural gas business. Kelt has limited direct experience in the marketing of oil and natural gas.

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. There is no assurance that expenditures made on exploration by the Corporation will result in new discoveries of oil or natural gas in commercial quantities. It is difficult to project the costs of implementing an exploratory drilling program due to the inherent uncertainties of drilling in unknown formations, the costs associated with encountering various drilling conditions such as over pressured zones and tools lost in the hole, and changes in drilling plans and locations as a result of prior exploratory wells or additional seismic data and interpretations thereof. 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, the Corporation's existing reserves, and the production from them, will decline over time as the Corporation produces from such reserves. A future increase in the Corporation's reserves will depend on both the ability of the Corporation to explore and develop its existing properties and on its ability to select and acquire suitable producing properties or prospects. There is no assurance that the Corporation will be able continue to find satisfactory properties to acquire or participate in. Moreover, management of the Corporation may determine that current markets, terms of acquisition, participation or pricing conditions make potential acquisitions or participations uneconomic. There is also no assurance that the Corporation will discover or acquire further commercial quantities of oil and natural gas.

Future oil and gas exploration may involve unprofitable efforts, not only from dry wells but from wells that are productive but do not produce sufficient net revenues to return a profit after drilling, completing, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs.

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, but are not limited to, 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, it is not possible to eliminate production delays and declines from normal field operating conditions, which can negatively affect revenue and cash flow levels to varying degrees.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including, but not limited to, fire, explosion, blowouts, cratering and spills or other environmental hazards. These typical risks and hazards could result in substantial damage to oil and natural gas wells, production facilities, other property, the environment and personal injury.

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.

As is standard industry practice, the Corporation is not fully insured against all risks, nor are all risks insurable. Although the Corporation maintains liability insurance in an amount that it considers consistent with industry practice, liabilities associated with certain risks could exceed policy limits or not be covered. In either event the Corporation could incur significant costs. See "*Risk Factors– Insurance*" in this Annual Information Form.

Possible Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

As part of its ongoing strategy, the Corporation may complete acquisitions of assets or other entities in the future. Achieving the benefits of completed and future acquisitions depends in part on successfully consolidating functions and integrating operations, procedures and personnel in a timely and efficient manner, as well as the Corporation's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Corporation. The integration of acquired businesses and entities requires the dedication of substantial management effort, time and resources which may divert management's focus and resources from other strategic opportunities and from operational matters during this process. The integration process may result in the loss of key employees and the disruption of ongoing business, customer and employee relationships that may adversely affect the Corporation's ability to achieve the anticipated benefits of any acquisitions. In addition, non-core assets may be periodically disposed of so the Corporation can focus its efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain non-core assets of the Corporation, if disposed of, may realize less than their carrying value on the financial statements of the Corporation.

Capital Markets

Kelt, along with all other oil and gas entities, may have restricted access to capital, bank debt and equity. The lending capacity of all financial institutions has diminished and risk premiums have increased. As future capital expenditures will be financed out of funds generated from operations, non-core property dispositions, borrowings and possible future equity sales, Kelt's ability to do so is dependent on, among other factors, the overall state of capital markets and investor appetite for investments in the energy industry and Kelt's securities in particular.

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

Based on current funds available and expected funds generated from operations, Kelt believes it has sufficient funds available to fund its projected capital expenditures. However, if funds generated from operations are lower than expected or capital costs for these projects exceed current estimates, or if Kelt incurs major unanticipated expense

related to development or maintenance of its existing properties, it may be required to seek additional capital to maintain its capital expenditures at planned levels. Failure to obtain any financing necessary for Kelt's capital expenditure plans may result in a delay in development or production on Kelt's properties.

Impact of Future Financings on Market Price

In order to finance future operations or acquisitions opportunities, the Corporation may raise funds through the issuance of Common Shares or the issuance of debt instruments or securities convertible into Common Shares. The Corporation cannot predict the size of future issuances of Common Shares or the issuance of debt instruments or other securities convertible into Common Shares or the effect, if any, that future issuances and sales of the Corporation's securities will have on the market price of the Common Shares.

Regulatory

Various levels of governments impose extensive controls and regulations on oil and natural gas operations (exploration, production, pricing, marketing and transportation). Governments may regulate or intervene with respect to exploration and production activities, prices, taxes, royalties and the exportation of oil and natural gas. Amendments to these controls and regulations may occur from time to time in response to economic or political conditions. See "*Industry Conditions*" in this Annual Information Form. The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for crude oil and natural gas and increase the Corporation's costs, either of which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

In addition to regulatory requirements pertaining to the production, marketing and sale of oil and natural gas mentioned above, the Corporation's business and financial condition could be influenced by federal legislation affecting, in particular, foreign investment, through legislation such as the *Competition Act* (Canada) and the *Investment Canada Act* (Canada).

Royalty Regimes

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

Insurance

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

Operational Dependence

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

In addition, due to the current low and volatile commodity prices, many companies, including companies that may operate some of the assets in which Kelt has an interest, may be in financial difficulty, which could impact their ability to fund and pursue capital expenditures, carry out their operations in a safe and effective manner and satisfy regulatory requirements with respect to abandonment and reclamation obligations. If companies that operate some of the assets in which Kelt has an interest fail to satisfy regulatory requirements with respect to abandonment and reclamation obligations, Kelt may be required to satisfy such obligations and to seek recourse from such companies. To the extent that any of such companies go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency, it could result in such assets being shut-in, Kelt potentially becoming subject to additional liabilities relating to such assets and Kelt having difficulty collecting revenue due from such operators. Any of these factors could materially adversely affect Kelt's financial and operational results.

Project Risks

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

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

Because of these factors, Kelt 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.

Gathering and Processing Facilities and Pipeline Systems

The Corporation delivers its products through gathering, processing 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, processing and pipeline systems. The lack of availability of capacity in any of the gathering, processing and pipeline systems, and in particular the processing facilities, could result in the Corporation's inability to realize the full economic potential of its production or in a reduction of the price offered for the Corporation's production. Although pipeline expansions are ongoing, the lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to produce and to market oil and natural gas production. In addition, the pro-rationing of capacity on inter-provincial pipeline systems also 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 because of actions taken by regulators could also affect the Corporation's production, operations and financial results. Furthermore, 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 in constructing new infrastructure systems and facilities could harm the Corporation's business and, in turn, the Corporation's financial condition, results of operations and cash flows.

The Federal Government has signaled that it plans to review the National Energy Board approval for large projects. This may cause the timeframe for project approvals for current and future applications to increase.

Following major accidents in Lac-Mégantic, Quebec and North Dakota, the Transportation Safety Board of Canada and the U.S. National Transportation Board have recommended additional regulations for railway tank cars carrying crude oil. In June 2015, as a result of these recommendations, the Government of Canada passed the *Safe and Accountable Rail Act* which increased insurance obligations on the shipment of crude oil by rail and imposed a per tonne levy of \$1.65 on crude oil shipped by rail to compensate victims and for environmental cleanup in the event of a railway accident. In addition to this legislation, new regulations have implemented the TC-117 standard for all rail tank cars carrying flammable liquids which formalized the commitment to retrofit, and eventually phase out DOT-111 tank cars carrying crude oil. The increased regulation of rail transportation may reduce the ability of railway lines to alleviate pipeline capacity issues and add additional costs to the transportation of crude oil by rail. On July 13, 2016, the Minister of Transport (Canada) issued Protective Direction No. 38, which directed that the shipping of crude oil on DOT-111 tank cars end by November 1, 2016. Tank cars entering Canada from the United States will be monitored to ensure that they are compliant with Protective Direction No. 38.

A portion of the Corporation's production may, from time to time, be processed through facilities owned by third parties and over which the Corporation does not have control. From time to time these facilities may discontinue or decrease operations either as a result of normal servicing requirements or as a result of unexpected events. A discontinuation or decrease of operations could materially adversely affect the Corporation's ability to process its production and to deliver the same for sale.

Variations in Foreign Exchange Rates and Insurance Rates

World oil and gas prices are quoted in United States dollars and the price received by Canadian producers is therefore affected by the Canadian/U.S. dollar exchange rate, which will fluctuate over time. In recent years, the Canadian dollar increased materially in value against the United States dollar. More recently, the Canadian dollar has seen a material decrease in value against the United States dollar. Any material increases in the value of the Canadian dollar may negatively impact Kelt's operating entities production revenues. Any increase in the future Canadian/United States exchange rates could accordingly impact the future value of Kelt's reserves as determined by independent evaluators.

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

An increase in interest rates could result in a significant increase in the amount Kelt pays to service debt, which could negatively impact the market price of the Common Shares.

Substantial Capital Requirements; Liquidity

Kelt anticipates that it will make substantial capital expenditures for the acquisition, exploration development and production of oil and natural gas reserves in the future. If Kelt's future revenues or reserves decline, Kelt may have limited ability to expend the capital necessary to undertake or complete future drilling programs. There can be no assurance that debt or equity financing, or cash generated by operations 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 Kelt. Moreover, future activities may require Kelt to alter its capitalization significantly. The inability of Kelt to access sufficient capital for its operations could have a material adverse effect on Kelt's financial condition, results of operations or prospects.

Additional Funding Requirements

Kelt's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times. From time to time, Kelt 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 Kelt to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If Kelt's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect Kelt's ability to expend the necessary capital to replace its reserves or to maintain its production. If Kelt'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 be available on favourable terms. Any equity financing may result in a change of control of Kelt or holders of Common Shares suffering further dilution. Continued uncertainty in domestic and international credit markets could materially affect Kelt's ability to access sufficient capital for its

capital expenditures and acquisitions, and as a result, may have a material adverse effect on Kelt's ability to execute its business strategy and on its business, financial condition, results of operations and prospects.

Issuance of Debt

From time to time Kelt may enter into transactions to acquire assets or the shares of other corporations. These transactions may be financed partially or wholly with debt, which may increase Kelt's debt levels above industry standards. Neither Kelt's articles nor its bylaws limit the amount of indebtedness that Kelt may incur. The level of Kelt's indebtedness from time to time could impair Kelt's ability to obtain additional financing in the future on a timely basis to take advantage of business opportunities that may arise. Kelt's ability to meet its debt service obligations will depend on Kelt's future operations which are subject to prevailing industry conditions and other factors, many of which are beyond the control of Kelt. As certain of the indebtedness of Kelt bears interest at rates which fluctuate with prevailing interest rates, increases in such rates would increase Kelt's interest payment obligations and could have a material adverse effect on Kelt's financial condition and results of operations. Further, Kelt's indebtedness is secured by substantially all of Kelt's assets. In the event of a violation by Kelt of any of its loan covenants or any other default by Kelt on its obligations relating to its indebtedness, the lender could declare such indebtedness to be immediately due and payable and, in certain cases, foreclose on Kelt's assets.

Hedging

From time to time Kelt may enter into agreements to receive fixed prices on its oil and natural gas production to offset risk of revenue losses if commodity prices decline; however, if commodity prices increase beyond the levels set in such agreements, Kelt will not benefit from such increases. Similarly, from time to time Kelt may enter into agreements to fix the exchange rate of Canadian to United States dollars in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the United States dollar, however, if the Canadian dollar declines in value compared to the United States dollar, Kelt will not benefit from its fluctuating exchange rate. In addition, from time to time, Kelt may enter into agreements to fix the interest rate on its debt to offset the risk of higher interest expenses during a period of rising borrowing costs, however, if borrowing costs decline, Kelt will not be able to benefit from such declines.

Competition

The oil and gas industry is highly competitive. Kelt actively competes for reserve acquisitions, exploration leases, licences and concessions and skilled industry personnel with a substantial number of other oil and gas entities, many of which have significantly greater financial resources, staff and facilities than Kelt. Kelt's competitors include integrated oil and natural gas companies and numerous other independent oil and natural gas companies and individual producers and operators. Certain of Kelt's customers and potential customers may themselves explore for oil and natural gas and the results of such exploration efforts could affect Kelt's ability to sell or supply oil or gas to these customers in the future. Kelt's ability to successfully bid on and acquire additional property rights, to discover reserves to participate in drilling opportunities and to identify and enter into commercial arrangements with customers will be dependent upon developing and maintaining close working relationships with its future industry partners and joint operators and its ability to select and evaluate suitable properties and to consummate transactions in a highly competitive environment. Competitive factors in the distribution and marketing of oil and natural gas include price and methods and reliability of delivery and storage. Competition may also be presented by alternate fuel sources.

Cost of New Technologies

The oil industry is characterized by rapid and significant technological advancements and introductions of new products and services utilizing new technologies. Other oil and 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.

Alternatives to and Changing Demand for Petroleum Products

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

Title

Title to oil and natural gas interests is often not capable of conclusive determination without incurring substantial expense. In accordance with industry practice, Kelt will conduct such title reviews in connection with its principal properties as it believes are commensurate with the value of such properties. However, no absolute assurances can be given that title defects do not exist. If title defects do exist, it is possible that Kelt may lose all or a portion of its right title and interest in and to the properties to which the title defects relate.

Environmental Risks

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of international conventions and federal, provincial and municipal laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach may result in the imposition of fines and penalties, some of which may be material. 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 foreign governments and third parties and may require Kelt to incur costs to remedy such discharge. See "*Industry Conditions – Environmental Regulation*" in this Annual Information Form. No assurance can be given that the application of environmental laws to the business and operations of Kelt will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise adversely affect Kelt's financial condition, results of operations or prospects.

Climate Change

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. Current greenhouse gas ("**GHG**") emissions legislation has not resulted in material compliance costs, however, it is not possible at this time to predict whether proposed legislation or regulations will be adopted, and any such future laws and regulations could result in additional compliance costs or additional operating restrictions.

Adverse impacts to the Corporation's business as a result of comprehensive GHG legislation or regulation applied to the Corporation's business in Alberta or any jurisdiction in which the Corporation operates, may include, but are not limited to: (i) increased compliance costs; (ii) permitting delays; (iii) substantial costs to generate or purchase emission credits or allowances adding costs to the products the Corporation produces; and (iv) reduced demand for crude oil and certain refined products. Emission allowances or offset credits may not be available for acquisition or may not be available on an economic basis. Required emission reductions may not be technically or economically feasible to implement, in whole or in part, and failure to meet such emission reduction requirements or other compliance mechanisms may have a material adverse effect on the Corporation's business resulting in, among other things, fines, permitting delays, penalties and the suspensions of operations. Consequently, no assurances can be given that the effect of future climate change regulations will not be significant to the Corporation.

Beyond existing legal requirements, the extent and magnitude of any adverse impacts of any additional programs or additional regulations cannot be reliably or accurately estimated at this time because specific legislative and regulatory requirements have not been finalized and uncertainty exists with respect to the additional measures being considered and the time frames for compliance. See "*Industry Conditions – Climate Change Regulation*" in this Annual Information Form.

Reserve Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and NGL reserves and cash flows to be derived therefrom, including many factors beyond Kelt's control. The information concerning reserves and associated cash flow set forth in this Annual Information Form represents 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 natural gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary 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 expected therefrom prepared by different engineers, or by the same engineers at different times, may vary. Kelt'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 the 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.

In accordance with applicable securities laws, Sproule has used forecast price and cost estimates in calculating reserve quantities. Actual future net cash flows will be affected by other factors such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs. Actual production and cash flows derived therefrom will vary from the estimates contained in the Sproule Report, and such variations could be material. The Sproule Report is based in part on the assumed success of activities Kelt intends to undertake in future years. The reserves and estimated cash flows to be derived therefrom contained in the Sproule Report will be reduced to the extent that such activities do not achieve the level of success assumed in the Sproule Report.

The Sproule Report is effective as of a specific effective date and has not been updated and thus does not reflect changes in Kelt's reserves since that date.

Reserve Replacement

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

Reliance on Key Personnel

Kelt's future success depends in large measure on certain key personnel. The exploration for, and the development and production of, oil and natural gas with respect to its assets requires experienced executive and management personnel and operational employees and contractors with expertise in a wide range of areas. There can be no assurance that all of the required employees and contractors with the necessary expertise will be available. Further, the loss of any key personnel may have a material adverse effect on Kelt's business, financial condition, results of operations and prospects. Kelt currently does not have any "key man" insurance in place.

Any inability on the part of Kelt to attract and retain qualified personnel may delay or interrupt the exploration for, and development and production of, oil and natural gas with respect to Kelt's assets. Sustained delays or interruptions could have a material adverse effect on the financial condition and performance of Kelt. In addition, rising personnel costs would adversely impact the costs associated with the exploration for, and development and production of, oil and natural gas in respect of Kelt's assets, which could be significant and material.

Management of Growth

Kelt may be subject to growth-related risks including capacity constraints and pressure on its internal systems and controls. The ability of Kelt to manage growth effectively will require it to continue to implement and improve its operations and financial systems and to expand, train and manage its employee base. The inability of Kelt to deal with this growth could have a material adverse impact on its business, operations and prospects.

Permits and Licenses

The operations of Kelt may require licenses and permits from various governmental authorities. There can be no assurance that Kelt will be able to obtain all necessary licenses and permits that may be required to carry out exploration and development at its projects. Further, if the Corporation or the holder of the licence or lease fails to meet the specific requirement of a licence or lease, the licence or lease may terminate or expire. There can be no assurance that any of the obligations required to maintain each licence or lease will be met. The termination or expiration of the Corporation's licenses 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.

Liability Management

Alberta and British Columbia have developed liability management programs designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licensee or permit holder 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 Kelt's deemed assets to deemed liabilities or changes to the requirements of liability management programs may result in significant increases to the security that must be posted. In addition, the liability management system may prevent or interfere with Kelt's ability to acquire or dispose of assets as both the vendor and the purchaser of oil and gas assets must be in compliance with the liability management programs (both before and after the transfer of the assets) for the applicable regulatory agency to allow for the transfer of such assets. See "*Industry Conditions - Liability Management Rating Programs*" in the Annual Information Form.

Availability of Drilling Equipment and Access Restrictions

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment 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 Kelt and may delay exploration and development activities.

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights to portions of western Canada. Kelt is not aware that any claims have been made in respect of its property and assets; however, if a claim arose and was successful this could have an adverse effect on Kelt and its operations.

Global Financial Markets

Market events and conditions, including disruptions in the international credit markets and other financial systems, and the deterioration of global economic conditions caused significant volatility to commodity prices over the last few years. These conditions have resulted in a loss of confidence in the broader U.S. and global credit and financial markets and resulting in the collapse of, and government intervention in, major banks, financial institutions and insurers and creating a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. These factors have negatively impacted company valuations and may continue to impact the performance of the global economy going forward.

If the economic climate in the U.S. or the world generally deteriorates further, demand for petroleum products could diminish further and prices for oil and natural gas could decrease further, which could adversely impact Kelt's results of operations, liquidity and financial condition.

Seasonality

The level of activity in the Canadian oil and gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Also, certain oil and gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. There can be no assurance that these seasonal factors will not adversely affect the timing and scope of Kelt's exploration and development activities, which could in turn have a material adverse impact on Kelt's business, operations and prospects.

Third Party Credit Risk

Kelt is, or may be exposed to, third party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production and other parties. In the event such entities fail to meet their contractual obligations to Kelt, such failures could have a material adverse effect on Kelt and its cash flow from operations. In addition, poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in Kelt's ongoing capital program, potentially delaying the program and the results of such program until Kelt finds a suitable alternative partner.

Hydraulic Fracturing

Concern has been expressed over the potential environmental impact of hydraulic fracturing operations, including water aquifer contamination and other qualitative and quantitative effects on water resources as large quantities of water are used and injected fluids either remain underground or flow back to the surface to be collected, treated and disposed of. Regulatory authorities in certain jurisdictions have announced initiatives in response to such concerns. Federal, provincial and local legislative and regulatory initiatives relating to hydraulic fracturing, as well as governmental reviews of such activities could result in increased costs, additional operating restrictions or delays, and adversely affect Kelt's production. Public perception of environmental risks associated with hydraulic fracturing can further increase pressure to adopt new laws, regulation or permitting requirements or lead to regulatory delays, legal proceedings and/or reputational impacts. Any new laws, regulations or permitting requirements regarding hydraulic fracturing could lead to operational delay, increased operating costs, and third-party or governmental claims. They could also increase Kelt's costs of compliance and doing business as well as delay the development of hydrocarbon (natural gas and oil) resources from shale formations, which may not be commercial without the use of hydraulic fracturing. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that Kelt is ultimately able to produce from its reserves.

In the event federal, provincial, local, or municipal legal restrictions are adopted in areas where Kelt is currently conducting, or in the future plan to conduct operations, Kelt may incur additional costs to comply with such requirements that may be significant in nature, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from the drilling of wells. In addition, if hydraulic fracturing becomes more regulated, Kelt's fracturing activities could become subject to additional permitting requirements and result in permitting delays as well as potential increases in costs. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that Kelt is ultimately able to produce from its reserves.

Political Uncertainty

In the last several years, the United States and certain European countries have experienced significant political events that have cast uncertainty on global financial and economic markets. During the recent United States presidential campaign a number of election promises were made and the new American administration has begun taking steps to implement certain of these promises. Included in the actions that the administration has discussed are the renegotiation of the terms of NAFTA, withdrawal of the United States from the Trans-Pacific Partnership, imposition of a tax on the importation of goods into the United States, reduction of regulation and taxation in the

United States, and introduction of laws to reduce immigration and restrict access into the United States for citizens of certain countries. It is presently unclear exactly what actions the new administration in the United States will implement, and if implemented, how these actions may impact Canada and in particular the oil and gas industry. Any actions taken by the new United States administration may have a negative impact on the Canadian economy and on the businesses, financial conditions, results of operations and the valuation of Canadian oil and natural gas companies, including the Corporation.

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

Geo-Political Risks

The marketability and price of oil and natural gas that may be acquired or discovered by Kelt 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 Kelt's net production revenue.

In addition, Kelt's expected oil and natural gas properties, wells and facilities could be subject to a terrorist attack. As the oil and gas industry in Canada is a key supplier of energy to the United States, certain terrorist groups may target Canadian oil and gas properties, wells and facilities in an effort to choke the United States economy. If any of Kelt's properties, wells or facilities are the subject of terrorist attack it could have a material adverse effect on Kelt. Kelt does not have insurance to protect against the risk from terrorism.

Tax Horizon

It is expected, based upon current legislation, the projections contained in the Sproule Report and various other assumptions that no cash income taxes are to be paid by Kelt in the near future. If a lower level of capital expenditures than those contained in the Sproule Report is incurred or, should the assumptions used by Kelt prove to be inaccurate, Kelt may be required to pay cash income taxes sooner than anticipated, which will reduce cash flow available to Kelt.

Potential Conflicts of Interest

There may be circumstances in which the interests of Kelt and its affiliates will conflict with those of shareholders. Kelt and its affiliates may acquire oil and natural gas properties on their own behalf or on behalf of persons other than the shareholders. Neither Kelt, nor its management, will carry on their full time activity on behalf of shareholders and, when acting on their own behalf or on behalf of others, may at times act in competition with the interests of shareholders.

In the event of such conflicts, decisions will be made on a basis consistent with the provisions of any relevant contractual arrangements and objectives and financial resources of each group of interested parties. Kelt will use all reasonable efforts to resolve such conflicts of interest in a manner which will treat Kelt, and the other interested party, fairly taking into account all of the circumstances of Kelt and such interested party and to act honestly and in good faith in resolving such matters.

Circumstances may arise where members of the Board of Directors are directors or officers of corporations which are in competition to the interests of Kelt. No assurances can be given that opportunities identified by such board members will be provided to Kelt.

Certain directors of Kelt 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. See “*Directors and Officers – Conflicts of Interest*” in this Annual Information Form.

Internal Controls

Effective internal controls are necessary for Kelt to provide reliable financial reports and to help prevent fraud. Although Kelt will undertake a number of procedures in order to help ensure the reliability of its financial reports, including those imposed on it under Canadian securities laws, Kelt cannot be certain that such measures will ensure that Kelt will maintain adequate control over financial processes and reporting.

Failure to implement required new or improved controls, or difficulties encountered in their implementation, could harm Kelt’s results of operations or cause it to fail to meet its reporting obligations. If Kelt or its independent auditors discover a material weakness, the disclosure of that fact, even if quickly remedied, could reduce the market’s confidence in Kelt financial statements and harm the trading price of the Common Shares.

Dividends

To date, Kelt has not paid any dividends on its Common Shares and does not anticipate the payment of any dividends on its Common Shares for the foreseeable future.

Dilution

Kelt may make future acquisitions or enter into financings or other transactions involving the issuance of securities of Kelt which may be dilutive. Common Shares, including rights, warrants, special warrants, subscription receipts and other securities to purchase, to convert into or to exchange into Common Shares, may be created, issued, sold and delivered on such terms and conditions and at such times as the Board of Directors may determine. In addition, the Corporation may issue additional Common Shares from time to time pursuant to the Corporation’s stock option plan or restricted share unit plan. The issuance of these Common Shares would result in dilution to holders of Common Shares.

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.

Breach of Confidentiality

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

Volatility of Market Price of Common Shares

The market price of the Common Shares may be volatile. The volatility may affect the ability of holders to sell the Common Shares at an advantageous price. Market price fluctuations in the Common Shares may be due to the Corporation’s operating results failing to meet the expectations of securities analysts or investors in any quarter,

downward revision in securities analysts' estimates, governmental regulatory action, adverse change in general market conditions or economic trends, acquisitions, dispositions or other material public announcements by the Corporation or its competitors, along with a variety of additional factors, including, without limitation, those set forth under "*Forward-Looking Statements and Information*" in this Annual Information Form. In addition, the market price for securities in the stock markets, including the TSX, has recently experienced significant price and trading fluctuations. These fluctuations have resulted in volatility in the market prices of securities that are often unrelated or disproportionate to changes in operating performance. These broad market fluctuations may adversely affect the market prices of the Common Shares.

Commodity Prices

The Corporation's operational and financial results are dependent on the prices received for oil and natural gas production. Any substantial and extended decline in the price of oil and natural gas would have an adverse effect on, among other things, the Corporation's revenues and financial condition.

Information Technology Systems and Cyber-Security

The Corporation relies heavily on information technology, such as computer hardware and software systems, in order to properly operate its business. In the event the Corporation is unable to regularly deploy software and hardware, effectively upgrade systems and network infrastructure, and take other steps to maintain or improve the efficiency and efficacy of systems, the operation of such systems could be interrupted or result in the loss, corruption, or release of data, compromise confidential customer or employee information, result in the disruption of business, theft or extortion of funds, regulatory infractions, loss of competitive advantage and reputational damage. In addition, information systems could be damaged or interrupted by natural disasters, force majeure events, telecommunications failures, power loss, acts of war or terrorism, computer viruses, malicious code, physical or electronic security breaches, intentional or inadvertent user misuse or error, or similar events or disruptions. Any of these or other events could cause interruptions, delays, loss of critical and/or sensitive data or similar effects, which could have a material adverse impact on the protection of intellectual property, and confidential and proprietary information, and on the Corporation's business, financial condition, results of operations and cash flows.

In the ordinary course of business, the Corporation collects, uses and stores sensitive data, including intellectual property, proprietary business information and personal information of the Corporation's employees and third parties. Despite the Corporation's security measures, its information systems, technology and infrastructure may be vulnerable to attacks by hackers and/or cyberterrorists or breaches due to employee error, malfeasance or other disruptions. Any such breach could compromise information used or stored on the Corporation's systems and/or networks and, as a result, the information could be accessed, publicly disclosed, lost or stolen. Any such access, disclosure or other loss of information could result in legal claims or proceedings, liability under laws that protect the privacy of personal information, regulatory penalties or other negative consequences, including disruption to the Corporation's operations and damage to its reputation, which could have a material adverse effect on the Corporation's business, financial condition, results of operations and cash flows.

Forward-Looking Statements and Information May Prove Inaccurate

Shareholders and prospective investors are cautioned not to place undue reliance on the Corporation's forward-looking statements and information. By its nature, forward-looking statements and information involve numerous assumptions, known and unknown risk and uncertainties, of both a general and specific nature, that could cause actual results to differ materially from those suggested by the forward-looking information or contribute to the possibility that predictions, forecasts or projections will prove to be materially inaccurate. Additional information on the risks, assumptions and uncertainties related to forward-looking statements and information are found under the heading "*Forward-Looking Statements and Information*" in this Annual Information Form.

INDUSTRY CONDITIONS

Canadian Government 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, Alberta and British Columbia, all of which should be carefully considered by investors in the oil and gas industry. It is not expected that any of these controls or regulations will affect the operations of Kelt in a manner materially different than they would affect other oil and gas companies of similar size. All current legislation is a matter of public record and Kelt is unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry in the provinces of Alberta and British Columbia.

Pricing and Marketing – 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. Worldwide supply and demand factors primarily determine oil prices; however prices are also influenced by regional market and transportation issues. The specific price depends in part on oil quality, prices of competing fuels, distance to market, the availability and cost of transportation capacity to various markets, value of refined products, the supply/demand balance and contractual terms of sale. Oil exporters are also entitled to enter into export contracts with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude oil, provided that an order approving such export has been obtained from the National Energy Board of Canada (the “NEB”). Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export licence from the NEB. The NEB underwent a consultation process to update the current regulations governing the issuance of export licences. The updating process was necessary to meet the criteria set out in the federal *Jobs, Growth and Long-term Prosperity Act* (Canada) (the “Prosperity Act”), which received Royal Assent on June 29, 2012. The *Regulations Amending the National Energy Board Act Part VI (Oil and Gas) Regulations* came into effect on July 31, 2015 and provides the requirements for obtaining long term licenses.

Pricing and Marketing – 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.

Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas (other than propane, butane and ethane) exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 m³ per day) must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or for a larger quantity requires an exporter to obtain an export licence from the NEB.

Pricing and Marketing – Natural Gas Liquids

In Canada, the price of NGL sold in intraprovincial, interprovincial and international trade is determined by negotiation between buyers and sellers. Such price depends, in part, on the quality of the NGL, prices of competing chemical feed stock, distance to market, access to downstream transportation, length of contract term, the supply/demand balance and other contractual terms. NGL exported from Canada are subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain criteria prescribed by the NEB and the Government of Canada. NGL may be exported for a term of no more than one year in respect of propane and butane, and no more than two years in respect of ethane, all exports requiring an order of the NEB.

Pipeline Capacity

Although pipeline expansions are ongoing, the lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to produce and to market natural gas production. The pro rating of capacity on the interprovincial pipeline systems also continues to affect the ability to export oil and natural gas.

The North American Free Trade Agreement

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

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

Provincial Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations which govern land tenure, royalties, production rates and other matters. The royalty regime in a given province is a significant factor in the profitability of crude oil, NGL, sulphur and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiation between the mineral freehold owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Royalties from production on Crown lands are determined by governmental regulation and are generally calculated as a percentage of the value of gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery and the type or quality of the petroleum product produced. Other royalties and royalty-like interests are, 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.

Occasionally the governments of the western Canadian provinces create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays or royalty tax credits and are generally introduced when commodity prices are low to encourage exploration and development activity by improving earnings and cash flow within the industry.

The federal government has signaled it will, *inter alia*, phase out subsidiaries for the oil and gas industry, which include only allowing the use of the Canadian Exploration Expenses tax deduction in cases of successful exploration, implementing more stringent reviews for pipelines, and establishing a pan-Canadian framework for combating climate change. These changes could affect earnings of companies operating in the oil and natural gas industry.

Alberta

On January 29, 2016, the Government of Alberta released and accepted the Royalty Review Advisory Panel’s recommendations, which outlined the implementation of a “Modernized Royalty Framework” for Alberta (the “MRF”). The MRF formally took effect on January 1, 2017. Wells drilled prior to January 1, 2017 will continue to

be governed by the current “Alberta Royalty Framework” for a period of 10 years until January 1, 2027. The MRF is structured in three phases: (i) Pre-Payout, (ii) Mid-Life, and (iii) Mature. During the Pre-Payout phase, a fixed 5% royalty will apply until the well reaches payout. Well payout occurs when the cumulative revenue from a well is equal to the Drilling and Completion Cost Allowance (determined by a formula that approximates drilling and completion costs for wells based on depth, length and historical costs). The new royalty rate will be payable on gross revenue generated from all production streams (oil, gas and natural gas liquids), eliminating the need to label a well as “oil” or “gas”. Post-payout, the Mid-Life phase will apply a higher royalty rate than the Pre-Payout phase. Depending on the commodity price of the substance the well is producing, the royalty rate could range from 5% - 40%. The metrics for calculating the Mid-Life phase royalty are based on commodity prices and are intended, on average, to yield the same internal rate of return as under the Alberta Royalty Framework. In the Mature phase, once a well reaches the tail end of its cycle and production falls below a Maturity Threshold, the equivalent of 194m³ (40 BOE/d or 345,500m³ of gas per month), the royalty rate will move to a sliding scale (based on volume and price) with a minimum royalty rate of 5%. The downward adjustment of the royalty rate in the Mature phase is intended to account for the higher per-unit fixed cost involved in operating an older well. Details of the MRF, including the applicable royalty rates and formulas, were released on April 21, 2016.

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

Royalties, for wells drilled prior to January 1, 2017 are paid pursuant to “The New Royalty Framework” (implemented by the *Mines and Minerals (New Royalty Framework) Amendment Act, 2008*) and the “Alberta Royalty Framework” until January 1, 2027. Royalty rates for conventional oil are set by a single sliding rate formula, which is applied monthly and incorporates separate variables to account for production rates and market prices. The maximum royalty payable under the royalty regime was 40%. Royalty rates for natural gas under the royalty regime are similarly determined using a single sliding rate formula incorporating separate variables to account for production rates and market prices. The maximum royalty payable under the royalty regime is 36%. Royalties on NGLs are levied at a flat rate of 30% of the sales volume for propane and butane and 40% for pentanes plus with field condensate at a rate equivalent to oil.

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% of revenues reported from fee simple mineral title properties.

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

In addition, the Government of Alberta has implemented certain initiatives intended to accelerate technological development and facilitate the development of unconventional resources. These initiatives apply to wells drilled before January 1, 2017 for a 10 year period until January 1, 2027. Specifically:

- coalbed methane wells will receive a maximum royalty rate of 5% for 36 producing months on up to 750 MMcf of production, retroactive to wells that began producing on or after May 1, 2010;
- shale gas wells will receive a maximum royalty rate of 5% for 36 producing months with no limitation on production volume, retroactive to wells that began producing on or after May 1, 2010;

- horizontal gas wells will receive a maximum royalty rate of 5% for 18 producing months on up to 500 MMcf of production, retroactive to wells that commenced drilling on or after May 1, 2010; and
- horizontal oil wells and horizontal non-project oil sands wells will receive a maximum royalty rate of 5% with volume and production month limits set according to the depth of the well (including the horizontal distance), retroactive to wells that commenced drilling on or after May 1, 2010.

On July 11, 2016, the Government of Alberta released details of the Enhanced Hydrocarbon Recovery Program and the Emerging Resources Program. These programs, which came into effect on January 1, 2017, are a part of the MRF and account for the higher costs associated with enhanced recovery methods and with developing emerging resources, respectively, in an effort to make difficult investments economically viable and to increase royalties. Certain eligibility criteria must be satisfied in order for a proposed project to fall under each program. Enhanced recovery scheme applications can be submitted to the Alberta Energy Regulator (the “AER”).

British Columbia

Producers of oil and natural gas from Crown lands in British Columbia are required to pay annual rental payments, currently at a rate of \$3.50 per hectare for licences and \$7.50 per hectare for leases, and make monthly royalty payments in respect of oil and natural gas produced. The amount payable as a royalty in respect of oil depends on the type and vintage of the oil, the quantity of oil produced in a month and the value of that oil. Generally, oil is classified as either light or heavy and the vintage of oil is based on the determination of whether the oil is produced from a pool discovered before October 31, 1975 (“old oil”), between October 31, 1975 and June 1, 1998 (“new oil”), or after June 1, 1998 or through an Enhanced Oil Recovery (“EOR”) scheme (“third-tier oil”). The royalty calculation takes into account the production of oil on a well-by-well basis, the specified royalty rate for a given vintage of oil, the average unit selling price of the oil and any applicable royalty exemptions. Royalty rates are reduced on low productivity wells, reflecting the higher unit costs of extraction, and are the lowest for third-tier oil, reflecting the higher unit costs of both exploration and extraction.

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

Producers of oil and natural gas from freehold lands in British Columbia are required to pay monthly freehold production taxes. For oil, the level of the freehold production tax is based on the volume of monthly production. It is either a flat rate, or, at certain production levels, is determined using a sliding scale formula based on the reference price similar to that applied to oil production on Crown land. For natural gas, the freehold production tax is either a flat rate, or, at certain production levels, is determined using a sliding scale formula based on the reference price similar to that applied to natural gas production on Crown land, and depends on whether the natural gas is conservation gas or non-conservation gas. The freehold production tax rate for natural gas liquids is a flat 12.25%.

As of January 1, 2017, all liquid natural gas (“LNG”) facilities are subject to a 3.5% income tax. This income tax is scheduled to increase to 5% in 2037. During the period in which net operating losses and capital investment are deducted, a tax rate of 1.5% will apply to the taxpayer’s net income. Once the net operating losses and capital investment have been depleted, the full rate of 3.5% is payable. To encourage investment, the Government of British Columbia will offer a corporate income tax credit to any LNG taxpayer based on the amount of LNG acquired for an LNG facility.

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

- *Deep Well Royalty Credit Program* providing a royalty credit for natural gas wells defined in terms of a dollar amount applied against royalties, is well specific and applies to drilling and completion costs for

vertical wells with a true vertical depth greater than 2,500 metres and horizontal wells with a true vertical depth greater than 1,900 metres (or 2,300 metres if spud before September 1, 2009) and if certain other criteria are met and is intended to reflect the higher drilling and completion costs that relate to locations specific factors. Effective April 1, 2014, the Deep Well Royalty Credit Program will have two tiers – “tier one” and “tier two”. The existing Deep Royalty Credit Program, as described above, will comprise tier two of the program which offers a higher maximum royalty credit and attracts a 3% minimum royalty. Tier one of the Deep Royalty Credit Program applies to shallower horizontal wells with a true vertical depth less than 1,900 metres if spud on or after April 1, 2014 and attracts a 6% minimum royalty.

- *Deep Re-Entry Royalty Credit Program* providing a royalty credit for deep re-entry wells with a true vertical depth to the top of pay of the re-entry well event that is greater than 2,300 metres and a re-entry date subsequent to December 1, 2003; or if the well was spud on or after January 1, 2009, with a true vertical depth to the completion point of the re-entry well event being greater than 2,300 metres.
- *Deep Discovery Royalty Credit Program* providing the lesser of a 3-year royalty holiday or 283,000,000 m³ of royalty free gas for deep discovery wells with a true vertical depth greater than 4,000 metres whose surface locations are at least 20 kilometres away from the surface location of any well drilled into a recognized pool within the same formation.
- *Coalbed Gas Royalty Reduction and Credit Program* providing a royalty reduction for coalbed gas wells with average daily production less than 17,000 m³ as well as a royalty credit for coalbed gas wells equal to \$50,000 for wells drilled on Crown land and a tax credit equal to \$30,000 for wells drilled on freehold land.
- *Marginal Royalty Reduction Program* providing a monthly royalty reduction for low productivity natural gas wells with an average daily rate of production less than 23 m³ for every metre of marginal well depth in the first 12 months of production. To be eligible, wells must have been spudded after May 31, 1998 and the first month of marketable gas production must have occurred between June 2003 and August 2008. Once a well passes the initial eligibility test, a reduction is realized in each month that average daily production is less than 25,000 m³.
- *Ultra-Marginal Royalty Reduction Program* providing royalty reductions for low productivity, shallow natural gas wells. Vertical wells must be less than 2,500 metres and horizontal wells less than 2,300 metres to be eligible. Production in the first 12 months ending after January 2007 must be less than 17 m³ per metre of depth for exploratory wildcat wells and less than 11 m³ per metre of depth for development wells and exploratory outpost wells. The well must have been spudded or re-entered after December 31, 2005. A reduction is realized in each month that average daily production is less than 60,000 m³. Horizontal wells that are spud on or after April 1, 2014 are not eligible for the Ultra-Marginal Royalty Reduction Program due to the potential for overlap with shallower horizontal wells eligible for a royalty credit under the Deep Well Royalty Credit Program.
- *Net Profit Royalty Reduction Program* providing reduced initial royalty rates to facilitate the development and commercialization of technically complex resources such as coalbed gas, tight gas, shale gas and enhanced-recovery projects, with higher royalty rates applied once capital costs have been recovered.

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

The Government of British Columbia also maintains an Infrastructure Royalty Credit Program which provides royalty credits for up to 50% of the cost of certain approved road construction or pipeline infrastructure projects intended to facilitate increased oil and gas exploration and production in under-developed areas and to extend the drilling season.

The Petroleum and Natural Gas Royalty and Freehold Production Tax Regulation has been amended effective April 1, 2013 to provide for a 3% minimum royalty on affected wells with deep well/deep re-entry credits. The 3% minimum royalty applies to deep wells when the net royalty payable would otherwise be zero for a production month. The amended regulation will be applied to royalties starting with the April 2013 production month. The 3% minimum royalty began showing on monthly gas royalty invoices starting in July 2013.

Land Tenure

The respective provincial governments predominantly own the rights to crude oil and natural gas located in the western provinces. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences, and permits for varying terms, and on conditions set forth in provincial legislation including requirements to perform specific work or make payments. Private ownership of oil and natural gas also exists in such provinces and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

Each of the provinces of Alberta and British Columbia 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. On March 29, 2007, British Columbia expanded its policy of deep rights reversion for new leases to provide for the reversion of both shallow and deep formations that cannot be shown to be capable of production at the end of their primary term.

Alberta also has a policy of “shallow rights reversion” which provides for the reversion to the Crown of mineral rights to shallow, non-productive geological formations for all leases and 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 intermediate term of the license.

Production and Operation Regulations

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

Environmental Regulation

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

Federal

On a Federal level and pursuant the Prosperity Act, the Government of Canada amended or appealed several pieces of federal environmental legislation and in addition, created a new federal environment assessment regime. The changes to the environmental legislation under the Prosperity Act are intended to provide for more efficient and timely environmental assessments of projects that previously had been subject to overlapping legislative jurisdiction.

On June 20, 2016, the federal government launched a review of current environmental and regulatory processes with a focus on rebuilding trust in the environmental assessment processes, modernizing the NEB, and introducing modernized safeguards to both the *Fisheries Act* and the *Navigation Protection Act*. An expert panel has been convened and is expected to complete its work by March 31, 2017. At such time, the Minister of Environment and Climate Change will consider the recommendations in the panel’s report and identify next steps to improve federal environmental processes, which is expected to take place during the summer/fall of 2017. Until this process is

complete, the federal government's interim principles released January 27, 2016 will continue to guide decision-making authorities for projects currently undergoing environmental assessment processes. The federal government has not provided any indication on what changes, if any, will be implemented or when, but increased delays and uncertainty surrounding the environmental assessment process should be expected for large projects.

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

Alberta

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

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

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

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

On August 22, 2012, the Government of Alberta approved the Lower Athabasca Regional Plan ("LARP") which came into effect on September 1, 2012. The LARP is the first of seven regional plans developed under the ALUF.

LARP covers approximately 93,212 square kilometres and is in the northeast corner of Alberta. The region includes a substantial portion of the Athabasca oilsands area, which contains approximately 82 per cent of the provinces oilsands resource and much of the Cold Lake oilsands area. LARP establishes six new conservation areas and nine new provincial recreation areas. In conservation and provincial recreation areas, conventional oil and gas companies with pre-existing tenure may continue to operate. Any new petroleum and gas tenure issued in conservation and recreation areas will include a restriction that prohibits surface access.

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

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

Phase 1 Consultation of the North Saskatchewan Region Plan (“NSRP”) has been completed and the Regional Advisory Council is currently preparing its Recommendation to Government report. The NSRP is located in central Alberta and is approximately 85,780 square kilometres in size. The Upper Peace Region Plan, Lower Peace Region Plan, Red Deer Region Plan and Upper Athabasca Region Plan have not been started.

British Columbia

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

Liability Management Rating Programs

Alberta

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

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

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

As a result of the Redwater Energy Corp. bankruptcy court ruling, whereby the court found that receivers and trustees of AER licensees may selectively disclaim unprofitable assets (and their associated abandonment and reclamation obligations) under section 14.06 of the federal *Bankruptcy and Insolvency Act*, the AER and the Orphan Well Association are actively working on appropriate regulatory measures to mitigate the liability impact of licensee’s abandonment, reclamation and remediation obligations from falling back to the industry. Consequently, 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**”) which includes an interim rule that 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 ratio (“**LMR**”) of 2.0 or higher immediately following the transfer. If the transfer of the licensee does not improve the purchaser’s LMR to 2.0 (or higher), the purchaser can post a security deposit, address existing abandonment obligations or transfer additional assets.

In order to clarify and revise the interim rules in Bulletin 16, the AER issued Bulletin 2016-21: *Revision and Clarification on Alberta Energy Regulator’s Measures to Limit Environmental Impacts Pending Regulatory Changes to Address the Redwater Decision* (“**Bulletin 21**”) on July 8, 2016 and reaffirmed its position that a LMR of 1.0 is not sufficient to ensure that licensees will be able to address their obligations throughout the life cycle of energy development, and 2.0 remains the requirement for transferees. However, Bulletin 21 did provide the AER with additional flexibility to permit licensees to acquire additional AER-licensed assets if: (i) the licensee already has a LMR of 2.0 or higher; (ii) the acquisition will improve the licensee’s LMR to 2.0 or higher; or (iii) the licensee is able to satisfy its obligations, notwithstanding a LMR below 2.0, by other means. The AER provided no indication of what other means would be considered. In the short term the interim measures caused delays in completing transactions and reduced the pool of possible purchasers, however, transactions have been approved following a more rigorous review by the AER, despite a transferee’s LMR not meeting the interim requirement. The Alberta Court of Appeal heard the appeal of the Redwater decision on October 11, 2016, with the Court reserving its decision.

British Columbia

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

Climate Change Regulation

Federal

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

On April 26, 2007, the Government of Canada released “*Turning the Corner: An Action Plan to Reduce Greenhouse Gases and Air Pollution*” (the “**Action Plan**”) which sets forth a plan for regulations to address both GHGs and air pollution. An update to the Action Plan, “*Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions*” was released on March 10, 2008 (the “**Updated Action Plan**”). The Updated Action Plan outlines emissions intensity-based targets, which will be applied to regulated sectors on either a facility-specific, sector-wide or company-by-company basis. Facility-specific targets apply to the upstream oil and gas, oil sands, petroleum refining and natural gas pipelines sectors. Unless a minimum regulatory threshold applies, all facilities within a regulated sector will be subject to the emissions intensity targets. Although the intention was for draft regulations for the implementation of the Updated Action Plan to become binding on January 1, 2010, the only regulations being implemented are in the transportation and electricity sectors. The federal government indicates that it is taking a sector-by-sector regulatory approach to reducing GHG emissions and is working on regulations for other sectors. Representatives of the Government of Canada have indicated that the proposals contained in the Updated Action Plan will be modified to ensure consistency with the direction ultimately taken by the United States with respect to GHG emissions regulation. In June 2012, the second US-Canada Clean Energy Dialogue Action Plan was released. The plan renewed efforts to enhance bilateral collaboration on the development of clean energy technologies to reduce GHG emissions.

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

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

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

Alberta

Alberta enacted the *Climate Change and Emissions Management Act* (the “**CCEMA**”) on December 4, 2003, amending it through the *Climate Change and Emissions Management Amendment Act*, which received royal assent on November 4, 2008. The CCEMA is based on an emissions intensity approach similar to the Updated Action Plan and aims for a 50% reduction from 1990 emissions relative to GDP by 2020. The accompanying regulations include the Specified Gas Emitters Regulation (“**SGER**”), which imposes GHG limits. The SGER applies to facilities emitting more than 100,000 tonnes of GHG emissions in 2003 or any subsequent year (“**Regulated Emitters**”), and

requires reductions in GHG emissions intensity (e.g. the quantity of GHG emissions per unit of production) from emissions intensity baselines established in accordance with the SGER.

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

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

Alberta Climate Leadership Plan

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

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

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

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

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

British Columbia

In February 2008, British Columbia announced a revenue-neutral carbon tax that took effect July 1, 2008. The tax is consumption-based and applied at the time of retail sale or consumption of virtually all fossil fuels purchased or used in British Columbia. The current tax level is \$30 per tonne of CO₂ equivalent. The final scheduled increase took effect on July 1, 2012. There is no plan for further rate increases or expansions at this time. In order to make the tax revenue-neutral, British Columbia has implemented tax credits and reductions in order to offset the tax revenues that the Government of British Columbia would otherwise receive from the tax.

In their 2012 Budget, British Columbia announced the government will undertake a comprehensive review of the carbon tax and its impact on British Columbians. The review will cover all aspects of the carbon tax, including revenue neutrality, and will consider the impact on the competitiveness of British Columbia businesses such as those in the agriculture sector, and in particular, British Columbia's food producers. After the review last year, British Columbia confirmed it will keep its revenue-neutral carbon tax, the current carbon tax rates and tax base will be maintained, and revenues will continue to be returned through tax reductions.

On April 3, 2008, British Columbia introduced the *Greenhouse Gas Reduction (Cap and Trade) Act* (the “**Cap and Trade Act**”) which received royal assent on May 29, 2008 and partially came into force by regulation of the Lieutenant Governor in Council. It sets a province-wide target of a 33% reduction in the 2007 level of GHG emissions by 2020 and an 80% reduction by 2050. Unlike the emissions intensity approach taken by the federal government and the Government of Alberta, the Cap and Trade Act establishes an absolute cap on GHG emissions. The Cap and Trade Act sets out the requirements for the reporting of the GHG emissions from facilities in British Columbia emitting 10,000 tonnes or more of carbon dioxide equivalent emissions per year beginning on January 1, 2010. Those reporting operations with emissions of 25,000 tonnes or greater are required to have emissions reports verified by a third party. The reporting system for large emitters of GHGs has since been streamlined by the *Greenhouse Gas Industrial Reporting and Control Act* (the “**GGIRCA**”) and its associated regulations that came into force on January 1, 2016. The GGIRCA sets out benchmarked performance standards for different industrial facilities and sectors, provides for emissions offsets through the purchase of emission credits or emission offsetting projects, among other measures, and replaces the Cap and Trade Act.

On August 19, 2016, the Government of British Columbia unveiled its Climate Leadership Plan with a goal to reduce net annual GHG emissions by up to 25 million tonnes below current forecasts by 2050, and reaffirmed that it will achieve its 2050 target of an 80% reduction in emissions from 2007 levels. In addition to various measures across the economy that are designed to incentivize the growth of the renewable energy sector, the use of low GHG emitting technologies, and the improvement of energy efficiency, among other goals, the Government of British Columbia will soon implement a formal policy to regulate carbon capture and storage projects. Further, the Climate Leadership Plan sets out a strategy to reduce methane emissions in the upstream natural gas sector, beginning with a Legacy phase that targets a 45% reduction in fugitive and vented emissions by 2025 for facilities built before January 1, 2015, followed by a Transition phase for facilities built between 2015 and 2018 that involves a new offset protocol and a Clean Infrastructure Royalty Credit Program along with other incentives, and finally a Future phase that will implement standards going forward.

DIVIDEND POLICY

There are no restrictions in Kelt's articles or elsewhere which could prevent Kelt from paying dividends. It is not currently contemplated that any dividends will be paid on any shares of Kelt in the immediate future, as it is anticipated that all available funds will be invested to finance the growth of Kelt's business. The Board of Directors will determine if, and when, dividends will be declared and paid in the future from funds properly applicable to the payment of dividends based on Kelt's financial position at the relevant time. Any decision to pay dividends on any shares of Kelt will be made by the Board of Directors on the basis of Kelt's earnings, financial requirements and other factors existing at such future time, including, but not limited to, commodity prices, production levels, capital expenditure requirements, debt service requirements, if any, operating costs, royalty burdens, foreign exchange rates and the satisfaction of the liquidity and solvency tests imposed by the ABCA for the declaration and payment of dividends.

DESCRIPTION OF SHARE CAPITAL

Kelt is authorized to issue an unlimited number of Common Shares and an unlimited number of Preferred Shares, of which 168,692,600 Common Share and no Preferred Shares are issued and outstanding as at the date of this Annual Information Form. See “*Prior Sales*” in this Annual Information Form.

The following is a description of the rights, privileges, restrictions and conditions attaching to the Common Shares and the Preferred Shares.

Common Shares

The holders of Common Shares are entitled to receive notice of and to attend at and to vote one vote per Common Share at meetings of shareholders, to receive dividends declared on the Common Shares, subject to the rights of the holders of shares ranking prior to the Common Shares and to receive *pro rata* the remaining property upon dissolution in equal rank with the holders of other Common Shares.

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 of Directors who may also 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 payment of dividends and distributions of assets in the event of liquidation, dissolution or winding-up of Kelt, whether voluntary or involuntary, or any other distribution of the assets of Kelt among its shareholders for the purpose of winding-up its affairs, rank equally with the Preferred Shares of every other series and shall be entitled to preference over the Common Shares, and the shares of any other class ranking junior to the Preferred Shares.

MARKET FOR SECURITIES

Trading Price and Volume

The following table sets forth the reported high and low sales prices (which are not necessarily the closing prices) and the trading volumes for the Common Shares of Kelt on the Toronto Stock Exchange as reported by sources Kelt believes to be reliable for the periods indicated:

Date	Price Range (\$)		Trading Volume
	High	Low	
2016			
January	4.44	2.51	25,203,000
February	3.92	2.81	19,865,459
March	4.49	3.49	37,048,712
April	5.04	3.42	34,736,271
May	4.93	3.92	32,205,104
June	5.60	4.22	31,782,092
July	4.91	4.22	24,298,023
August	5.26	4.39	32,460,697
September	6.04	4.66	43,182,184
October	6.98	5.70	39,112,117
November	6.57	5.43	36,113,601
December	7.06	6.32	21,593,187
2017			
January	7.49	6.26	25,555,799
February	6.60	5.81	17,847,914
March 1-9	6.36	5.73	5,923,264

The following table sets forth the reported high and low sales prices (which are not necessarily the closing prices) and the trading volume for the Kelt Debentures on the Toronto Stock Exchange as reported by sources Kelt believes to be reliable for the periods indicated:

Date	Price Range (\$)		Trading Volume
	High	Low	
2016			
May 3-31 ⁽¹⁾	117.75	105.50	186,610
June	126.00	114.00	13,920
July	117.00	113.00	11,550
August	124.50	112.00	68,710
September	133.00	120.00	22,160
October	146.00	130.00	26,120
November	144.00	138.02	5,640
December	150.02	144.00	6,060
2017			
January	147.00	139.00	61,570
February	145.00	145.00	40
March 1-9	-	-	-

Note:

- (1) The Kelt Debentures were listed and posted for trading on the TSX under the symbol KEL.DB at the open of markets on May 3, 2016.

PRIOR SALES

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

Class of Securities	Issue Price or Exercise Price \$	Number of Securities Issued	Date of Issue
RSUs	N/A	5,500	January 11, 2016
Options	3.67	15,000	January 11, 2016
RSUs	N/A	4,000	January 18, 2016
Options	3.25	12,000	January 18, 2016
RSUs	N/A	2,100	February 1, 2016
Options	3.91	4,500	February 1, 2016
RSUs	N/A	60,000	March 11, 2016
Options	3.93	310,000	March 11, 2016
RSUs	N/A	15,000	April 20, 2016
Options	3.90	50,000	April 20, 2016
RSUs	N/A	174,460	June 2, 2016
Options	4.72	1,540,800	June 6, 2016
RSUs	NA	20,000	June 20, 2016
Options	4.79	80,000	June 20, 2016
RSUs	N/A	20,000	June 28, 2016
Options	4.52	70,000	June 28, 2016
RSUs	N/A	11,000	July 4, 2016
Options	4.61	31,000	July 4, 2016
RSUs	N/A	57,000	August 17, 2016
Options	4.86	180,000	August 17, 2016
RSUs	N/A	3,000	August 29, 2016
Options	4.93	8,500	August 29, 2016
RSUs	N/A	30,000	September 19, 2016
Options	5.37	80,000	September 19, 2016
RSUs	N/A	1,000	October 3, 2016
Options	5.78	6,000	October 3, 2016
RSUs	N/A	6,000	October 19, 2016
Options	6.38	20,000	October 19, 2016

Class of Securities	Issue Price or Exercise Price \$	Number of Securities Issued	Date of Issue
RSUs	N/A	30,000	November 18, 2016
Options	6.16	125,000	November 18, 2016

As at the date of this Annual Information Form, the Corporation has 8,339,700 Options and 693,096 RSUs outstanding.

ESCROWED SECURITIES

As at the date of this Annual Information Form, to the knowledge of the Corporation, no securities of any class of Kelt are held in escrow or are subject to a contractual restriction on transfer.

DIRECTORS AND OFFICERS

The following table provides the name, province and country of residence, positions held with Kelt and principal occupation during the preceding five years of each of the current directors and executive officers of Kelt.

Name, Province and Country of Residence	Offices Held and Time as Director or Officer	Principal Occupation During the Past 5 Years
Robert J. Dales ⁽¹⁾⁽²⁾⁽⁴⁾⁽⁵⁾ Alberta, Canada	Director since October 22, 2012	President of Valhalla Ventures Inc., a private Alberta investment corporation, from January 1999 to the present. President of Drako Capital Corp., a corporation engaged in oil and gas exploration and production, from January 2010 to August 2012.
Douglas J. Errico Alberta, Canada	Vice President, Land since October 22, 2012	Vice President, Land of Kelt. Prior thereto, Landman and then Senior Landman with Celtic from September 2005 to February 2013.
Alan G. Franks Alberta, Canada	Vice President, Production since October 22, 2012	Vice President, Production of Kelt. Prior thereto, Vice President, Operations of Celtic from December 2002 to February 2013.
Bruce D. Gigg Alberta, Canada	Vice President, Engineering since March 11, 2016	Vice President, Engineering of Kelt. Prior thereto, President of Giggajoule Energy Inc. from October 2014 to March 2016. Prior thereto Team Lead at NuVista Energy Ltd. from April 2005 to October 2014.
William C. Guinan ⁽³⁾ Alberta, Canada	Corporate Secretary and Director since October 22, 2012	Partner with Borden Ladner Gervais LLP.
Ashley D. Hohm Alberta, Canada	Vice President, Finance since March 11, 2016	Vice President, Finance of Kelt. Prior thereto, Controller of Kelt from February 2013 to March 2016. Prior thereto Manager, Financial Reporting of Celtic from June 2011 to February 2013.
Sadiq H. Lalani ⁽⁶⁾ Alberta, Canada	Vice President and Chief Financial Officer since October 22, 2012	Vice President and Chief Financial Officer of Kelt. Prior thereto, Vice President, Finance and Chief Financial Officer of Celtic from October 2002 to February 2013.
Douglas O. MacArthur Alberta, Canada	Vice President, Operations since October 22, 2012	Vice President, Operations of Kelt. Prior thereto, Operations Manager with Celtic from January 2007 to February 2013.
Eldon A. McIntyre ⁽¹⁾⁽²⁾⁽⁴⁾⁽⁵⁾ Alberta, Canada	Director since October 22, 2012	President of Jarrod Oils Ltd., a private Saskatchewan corporation engaged in oil and gas exploration and production, from 1980 to the present.
Patrick W.G. Miles Alberta, Canada	Vice President, Exploration since October 22, 2012	Vice President, Exploration of Kelt. Prior thereto, Geology Consultant with Celtic from November 2009 to February 2013.
Neil G. Sinclair ⁽¹⁾⁽²⁾⁽³⁾⁽⁴⁾⁽⁵⁾ British Columbia, Canada	Director since October 22, 2012	President of Sinson Investments Ltd., a private British Columbia corporation engaged in property development, from 1973 to the present.
David J. Wilson ⁽³⁾ Alberta, Canada	President, Chief Executive Officer and Director since October 11, 2012	President and Chief Executive Officer of Kelt. Prior thereto, President and Chief Executive Officer of Celtic from September 2002 to February 2013.

Notes:

- (1) Member of the Audit Committee.
- (2) Member of the Compensation Committee.
- (3) Member of the Health, Safety and Environment Committee.
- (4) Member of the Reserves Committee.
- (5) Member of the Nominating Committee.
- (6) On March 11, 2016 Mr. Lalani resigned as Vice President, Finance and was appointed Vice President of Kelt and at all times since October 22, 2012 Mr. Lalani has held the position of Chief Financial Officer of Kelt.

Each of the directors of Kelt will hold office until the first annual meeting of the holders of Common Shares or until his successor is duly elected or appointed, unless his office is earlier vacated in accordance with Kelt's articles or by-laws.

As at the date of this Annual Information Form, the current directors and officers of Kelt, as a group, beneficially owned, or controlled or directed, directly or indirectly, an aggregate of 30,994,126 Common Shares, representing approximately 17.64% of the issued and outstanding Common Shares and they hold 14,680 Kelt Debentures representing approximately 16.3% of the Kelt Debentures. The information as to the number of Common Shares beneficially owned, or controlled or directed, not being within the knowledge of the Corporation, has been furnished by the respective directors and officers of the Corporation individually.

Corporate Cease Trade Orders

None of the directors or executive officers of Kelt is or has been, within the 10 years prior to the date of this Annual Information Form, a director, chief executive officer or chief financial officer of any company (including Kelt) that: (i) was the subject of a cease trade or similar order or an order that denied the relevant company access to any exemption under securities legislation, that was in effect for a period of more than 30 consecutive days that was issued while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer; or (ii) was subject to a cease trade or similar 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, that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as a director, chief executive officer or chief financial officer.

Bankruptcies

None of the directors, executive officers or securityholders holding a sufficient number of securities of Kelt to affect materially the control of Kelt is or has, within the 10 years prior to the date of this Annual Information Form, been a director or executive officer of any company (including Kelt) that, while such 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.

In addition, none of the directors, executive officers or securityholders holding a sufficient number of securities of Kelt to affect materially the control of Kelt has, within the 10 years prior to the date of this Annual Information Form, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director, executive officer or securityholder.

Penalties or Sanctions

None of the directors, executive officers or securityholders holding a sufficient number of securities of Kelt to affect materially the control of Kelt has been subject to: (i) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority; or (ii) any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

Conflicts of Interest

There are potential conflicts of interest to which the directors and officers of Kelt may become subject in connection with the operations of Kelt. In particular, certain directors and officers of Kelt 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 Kelt or with entities which may, from time to time, provide financing to, or make equity investments in, competitors of Kelt. 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 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, Kelt is not aware of any existing or potential material conflicts of interest between Kelt and any director or officer of Kelt.

AUDIT COMMITTEE

Pursuant to NI 52-110, the Corporation is required to include in its Annual Information Form the disclosure required under Form 52-110F1 – *Audit Committee Information Required in an AIF* with respect to its audit committee, including the text of its audit committee charter, the composition of the audit committee and the fees paid to the external auditor. This information is provided in Appendix D attached hereto.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

Since the date of incorporation of Kelt, there have been no legal proceedings to which the Corporation is or was a party to, or that any of the Corporation's property is or was the subject of, which is or was, or can be reasonably considered to be, material to the Corporation or any of its properties and the Corporation is not aware of any such legal proceedings that are contemplated. For the purposes of the foregoing, a legal proceeding is not considered to be "material" by the Corporation if it involves a claim for damages and the amount involved, exclusive of interest and costs, does not exceed 10% of the Corporation's current assets, provided that if any proceeding presents in large degree the same legal and factual issues as other proceedings pending or known to be contemplated, the Corporation has included the amount involved in the other proceedings in computing the percentage.

Since the date of incorporation of Kelt, there have been no penalties or sanctions imposed against the Corporation by a court relating to securities legislation or by a securities regulatory authority, nor have there been any other penalties or sanctions imposed by a court or regulatory body against the Corporation, and the Corporation has not entered into any settlement agreements before a court relating to securities legislation or with a securities regulatory authority.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

None of the directors or executive officers of Kelt or any person or company that beneficially owns, or controls or directs, directly or indirectly, more than 10% of the Common Shares, or any associate or affiliate of any of the foregoing persons or companies, has or has had any material interest, direct or indirect, in any past transaction or any proposed transaction that has materially affected or is reasonably expected to materially affect Kelt.

TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for the Common Shares is Computershare Trust Company of Canada. The Common Shares are transferable at the offices of Computershare Trust Company of Canada in Calgary, Alberta and Toronto, Ontario.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, there are no material contracts entered into by Kelt since its incorporation and still in effect as at the date hereof that can be reasonably regarded as presently material.

INTERESTS OF EXPERTS

Sproule prepared the Sproule Report. The principals of Sproule own, directly or indirectly, less than 1% of the outstanding Common Shares as at the date of this Annual Information Form. Sproule neither received nor will receive any interest, direct or indirect, in any securities or other property of Kelt or its affiliates in connection with the preparation of the Sproule Report.

PricewaterhouseCoopers LLP, Chartered Professional Accountants, are the auditors of Kelt and have confirmed that they are independent with respect to Kelt in accordance with the Rules of Professional Conduct of the Chartered Professional Accountants of Alberta. PricewaterhouseCoopers LLP, Chartered Professional Accountants, were appointed the auditors of the Corporation on October 11, 2012.

ADDITIONAL INFORMATION

Additional information relating to the Corporation, including directors' and officers' remuneration and indebtedness, principal holders of Common Shares and securities authorized for issuance under equity compensation plans, is contained in the Corporation's Management Information Circular which relates to the Annual Meeting of Shareholders to be held on April 19, 2017 and which can be found on SEDAR under the Corporation's profile at www.sedar.com.

Additional financial information is provided in the Corporation's financial statements and management's discussion and analysis for the year ended December 31, 2016 filed under the Corporation's profile at www.sedar.com.

APPENDIX A

Form 51-101F2

Report on Reserves Data by Independent Qualified Reserves Evaluator or Auditor

To the Board of Directors of Kelt Exploration Ltd. (the “Company”):

1. We have evaluated or audited the Company’s reserves data as at December 31, 2016. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2016, estimated using forecast prices and costs.
2. The reserves data are the responsibility of the Company’s management. Our responsibility is to express an opinion on the reserves data based on our evaluation or audit.
3. We carried out our evaluation or audit 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 or audit to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation or audit 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 or audited for the year ended December 31, 2016, 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, 2016	Canada				
Total			38,990	1,691,700	Nil	1,730,690

6. In our opinion, the reserves data respectively evaluated or audited 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 the report referred to in paragraph 5 for events and circumstances occurring after the effective date of our report entitled “Evaluation of the P&NG Reserves of Kelt Exploration Ltd. (As of December 31, 2016).”
8. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

Sproule Associates Limited
Calgary, Alberta
February 7, 2017

(signed) "Brent A. Hawkwood"
Brent A. Hawkwood, C.E.T.
Senior Petroleum Technologist

(signed) "Charles Wong"
Charles Wong, P. Eng.
Petroleum Engineer

(signed) "Tanja M. Hale"
Tanja M. Hale, P.Eng.
Senior Petroleum Engineer

(signed) "Maren L. Blair"
Maren L. Blair, P. Geol
Petroleum Geologist

(signed) "Alec Kovaltchouk"
Alec Kovaltchouk, P. Geol.
Vice President, Geoscience

(signed) "Cameron P. Six"
Cameron P. Six, P. Eng.
Chief Operating Officer and Director

APPENDIX B

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

Report of Management and Directors on Reserves Data and Other Information

Management of Kelt Exploration Ltd. (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, 2016, estimated using forecast prices and costs.

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

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

- (a) reviewed the Company’s procedures for providing information to the independent qualified reserves evaluator;
- (b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and
- (c) reviewed the reserves data with management and the independent qualified reserves evaluator.

The Reserves Committee of the board of directors has reviewed the Company’s procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has, 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 evaluator 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.

(signed) "David J. Wilson"

David J. Wilson
President and Chief Executive Officer

(signed) "Bruce Gigg"

Bruce Gigg
Vice President, Engineering

(signed) "Neil G. Sinclair"

Neil G. Sinclair
Director

(signed) "Eldon A. McIntyre"

Eldon A. McIntyre
Director

Dated this 9th day of February, 2017.

APPENDIX C

DEFINITIONS USED FOR RESERVE CATEGORIES

The following definitions form the basis of the classification of reserves and values presented in the Sproule Report. They have been prepared by the Standing Committee on Reserves Definitions of the Petroleum Society of the CIM incorporated in the COGE Handbook and specified by NI 51-101.

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

- analysis of drilling, geological, geophysical and engineering data;
- the use of established technology;
- specified economic conditions, which are generally accepted as being reasonable, and shall be disclosed; and
- a remaining reserve life of 50 years.

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

1. **Proved Reserves**

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

2. **Probable Reserves**

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.

3. **Possible Reserves**

Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves. Possible reserves have not been considered in this report.

Other criteria that must also be met for categorization of reserves are provided in Section 5.5 of the COGE Handbook.

Each of the reserves categories (proved, probable, and possible) may be divided into developed or undeveloped categories.

4. **Developed Reserves**

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

5. **Developed Producing Reserves**

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.

6. Developed Non-Producing Reserves

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.

7. Undeveloped Reserves

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

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

8. Levels of Certainty for Reported Reserves

The qualitative certainty levels contained in the definitions in Sections 1, 2 and 3 are applicable to individual reserves entities, which refers to the lowest level at which reserves estimates are made, and to reported reserves, which refers to the highest level sum of individual entity estimates for which reserve estimates are made.

Reported total reserves estimated by deterministic or probabilistic methods, whether comprised of a single reserves entity or an aggregate estimate for multiple entities, should target the following levels of certainty under a specific set of economic conditions:

- (a) There is a 90% probability that at least the estimated proved reserves will be recovered.
- (b) There is a 50% probability that at least the sum of the estimated proved reserves plus probable reserves will be recovered.
- (c) There is a 10% probability that at least the sum of the estimated proved reserves plus probable reserves plus possible reserves will be recovered.

A quantitative measure of the probability associated with a reserves estimate is generated only when a probabilistic estimate is conducted. The majority of reserves estimates will be performed using deterministic methods that do not provide a 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 Section 5.5.3 of the COGE Handbook. Whether deterministic or probabilistic methods are used, evaluators are expressing their professional judgement as to what are reasonable estimates.

9. Remaining Recoverable Reserves are the total remaining recoverable reserves associated with the acreage in which the Company has an interest.

10. Company Gross Reserves are the Company's working interest share of the remaining reserves, before deduction of any royalties.

11. **Company Net Reserves** are the gross remaining reserves of the properties in which the Company has an interest, less all Crown, freehold, and overriding royalties and interests owned by others.
12. **Net Production Revenue** is income derived from the sale of net reserves of oil, pipeline gas, and gas by-products, less all capital and operating costs.
13. **Fair Market Value** is defined as the price at which a purchaser seeking an economic and commercial return on investment would be willing to buy, and a vendor would be willing to sell, where neither is under compulsion to buy or sell and both are competent and have reasonable knowledge of the facts.
14. **Barrels of Oil Equivalent (BOE) Reserves** - BOE is the sum of the oil reserves, plus the gas reserves divided by a factor of 6, plus the natural gas liquid reserves, all expressed in barrels or thousands of barrels. Equivalent reserves can also be expressed in thousands of cubic feet of gas equivalent (McfGE) using a conversion ratio of 1 bbl:6 Mcf.
15. **Oil (or Crude Oil)** – a mixture consisting mainly of pentanes and heavier hydrocarbons that exists in the liquid phase in reservoirs and remains liquid at atmospheric pressure and temperature. Crude oil may contain small amounts of sulphur and other non-hydrocarbons, but does not include liquids obtained from the processing of natural gas.
16. **Gas (or Natural Gas)** – a mixture of lighter hydrocarbons that exist either in the gaseous phase or in solution in crude oil in reservoirs, but are gaseous at atmospheric conditions. Natural gas may contain sulphur or other non-hydrocarbon compounds.
17. **Non-Associated Gas** – an accumulation of natural gas in a reservoir where there is no crude oil.
18. **Associated Gas** - the gas cap overlying a crude oil accumulation in a reservoir.
19. **Solution Gas** - gas dissolved in crude oil.
20. **Natural Gas By Products** – those components that can be removed from natural gas including, but not limited to, ethane, propane, butanes, pentanes plus, condensate, and small quantities of non-hydrocarbons.
21. **Products Types** – sub-classify the principle product types of petroleum, crude oil, gas and by-products, into specific groupings based on the properties of the hydrocarbon and the properties of the accumulation and reservoir rock from which it is found. Regulatory agencies may define in legislation the production types they require to be used for reporting purposes in their jurisdiction. The Canadian Securities Association (CSA) defines the following Product Types for reporting purposes in National Instrument 51-101, effective July 1, 2015.

Crude Oil

- (a) **Light Crude Oil** means crude oil with a relative density greater than 31.1 degrees API gravity.
- (b) **Medium Crude Oil** means crude oil with a relative density greater than 22.3 degrees API gravity and less than or equal to 31.1 degrees API gravity;
- (c) **Heavy Crude Oil** means crude oil with a relative density greater than 10 degrees API gravity and less than or equal to 22.3 degrees API gravity;
- (d) **Tight Oil** means crude oil:
 - (i) contained in dense organic rich rocks, including low-permeability shales, siltstones and carbonates, in which the crude oil is primarily contained in microscopic pore spaces that are poorly connected to one another, and

- (ii) that typically requires the use of hydraulic fracturing to achieve economic production rates;
- (e) **Bitumen** means a naturally occurring solid or semi-solid hydrocarbon:
 - (i) consisting mainly of heavier hydrocarbons, with a viscosity greater than 10,000 millipascal-seconds (mPa.s) or 10,000 centipoise (cP) measured at the hydrocarbon's original temperature in the reservoir and at atmospheric pressure on a gas-free basis, and
 - (ii) that is not primarily recoverable at economic rates through a well without the implementation of enhanced recovery methods;
- (f) **Synthetic Crude Oil** means a mixture of liquid hydrocarbons derived by upgrading bitumen, kerogen or other substances such as coal, or derived from gas to liquid conversion and may contain sulphur or other compounds;

Natural Gas

- (g) **Conventional Natural Gas** means natural gas that has been generated elsewhere and has migrated as a result of hydrodynamic forces and is trapped in discrete accumulations by seals that may be formed by localized structural, depositional or erosional geological features;
- (h) **CoalBed Methane** means natural gas that
 - (i) primarily consists of methane, and
 - (ii) is contained in a coal deposit;
- (i) **Shale Gas** means natural gas:
 - (i) contained in dense organic-rich rocks, including low-permeability shales, siltstones and carbonates, in which the natural gas is primarily absorbed on the kerogen or clay minerals, and
 - (ii) that usually requires the use of hydraulic fracturing to achieve economic production rates;
- (j) **Synthetic Gas** means a gaseous fluid:
 - (i) generated as a result of the application of an in-situ transformation process to coal or other hydrocarbon-bearing rock, and
 - (ii) comprised of not less than 10% by volume of methane;
- (k) **Gas Hydrate** means a naturally occurring crystalline substance composed of water and gas in an ice-lattice structure;

By-Products

- (l) **Natural Gas Liquids** means those hydrocarbon components that can be recovered from natural gas as a liquid including, but not, limited to, ethane, propane, butanes, pentanes plus and condensates; and
- (m) Sulphur is a non-hydrocarbon elemental by-product of gas processing and refining.

APPENDIX D
FORM 52-110F1 – AUDIT COMMITTEE INFORMATION REQUIRED IN AN AIF

1. The Audit Committee Charter

The charter of the Audit Committee is attached as Schedule 1 to this Appendix D.

2. Composition of the Audit Committee

The Audit Committee of the Corporation is composed of the following individuals:

Member	Independent	Financially literate
Robert Dales	Independent ⁽¹⁾	Financially literate ⁽²⁾
Eldon McIntyre	Independent ⁽¹⁾	Financially literate ⁽²⁾
Neil Sinclair	Independent ⁽¹⁾	Financially literate ⁽²⁾

Notes:

- (1) A member of an audit committee is independent if the member has no direct or indirect material relationship with the Corporation which could, in the view of the Board of Directors, reasonably interfere with the exercise of a member's independent judgment.
- (2) An individual is financially literate if he has the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and level of complexity of accounting issues that can reasonably be expected to be raised by the Corporation's financial statements.

3. Relevant Education and Experience

Mr. Dales holds an MBA. He also has over 22 years of public issuer experience, both as an officer and as a director.

Mr. McIntyre has been President of an active private corporation, with significant oil and gas operations, for over 36 years. He also has over 24 years of public issuer experience as a director.

Mr. Sinclair, the Chair of the Audit Committee, holds a BA and an MBA. He has also been President of an active private corporation, with significant real estate operations, for over 44 years. He also has over 15 years of public company experience as an officer and/or as a director.

4. Reliance on Certain Exemptions

At no time since incorporation has the Corporation relied on any exemption from NI 52-110, other than in Section 2.4 of NI 52-110 (*De Minimis Non-audit Services*).

5. Reliance on the Exemption in Subsection 3.3(2) or Section 3.6

At no time since incorporation has the Corporation relied on the exemptions in Sections 3.3(2) or 3.6 of NI 52-110.

6. Reliance on Section 3.8

At no time since incorporation has the Corporation relied on Section 3.8 of NI 52-110.

7. Audit Committee Oversight

At no time since incorporation was a recommendation of the Audit Committee to nominate or compensate an external auditor not adopted by the Board of Directors.

8. Pre-Approval Policies and Procedures

The Audit Committee of the Corporation has adopted specific policies and procedures for the engagement of non-audit services entitled “*Procedures for Approval of Audit and Non-Audit Services by the External Auditors*” (the “**Procedure**”). Under the Procedure, the auditors may not act in any capacity where they function as management, audit their own work or serve in an advocacy role on behalf of the Corporation. Various audit related services provided by the auditors have been pre-approved. Management is required, however, to obtain pre-approval of the Audit Committee for services where engagement fees are expected to exceed \$20,000. Where fees for a particular engagement are expected to be less than or equal to \$20,000 the Chair of the Audit Committee is to be notified expeditiously of the commencement of such services. If an engagement with the auditors for a particular service is contemplated that is neither expressly forbidden under the Procedure nor covered under the range of services provided for therein, such an engagement must be pre-approved. The Audit Committee has delegated the authority to effect such pre-approval to the Chair of the Audit Committee. Pre-approved non-audit services shall be provided pursuant to an engagement letter signed by the auditors which shall set out the particular non-audit services to be provided. At every regularly scheduled meeting of the Audit Committee, management is required to report on all new pre-approved engagements of the auditors since the last such report.

9. External Auditor Service Fees (By Category)

The aggregate fees billed by the Corporation’s external auditors in each of the last two fiscal years are set forth in the table below:

Year Ended	Audit Fees ⁽¹⁾	Audit-Related Fees ⁽²⁾	Tax Fees ⁽³⁾	All Other Fees ⁽⁴⁾
December 31, 2016	\$160,000	\$83,000	\$108,134	\$35,000
December 31, 2015	\$160,000	\$103,000	\$143,500	\$30,000

Notes:

- (1) The aggregate audit fees paid or payable.
- (2) Audit related services include quarterly reviews, procedures related to business acquisition reports, information circulars, and/or prospectuses.
- (3) The aggregate fees billed for professional services rendered for tax compliance, tax advice and tax planning.
- (4) NI 52-109 related fees and ESTMA Readiness Assessment.

SCHEDULE 1
AUDIT COMMITTEE CHARTER OF KELT EXPLORATION LTD.

This charter governs the operations of the audit committee (the “**Committee**”) of Kelt Exploration Ltd. (the “**Corporation**”). The Committee shall report to the Board of Directors (the “**Board**”) of the Corporation. The following is the text of the Committee’s charter.

I. PURPOSE

- (a) The primary function of the Committee is to assist the Board in fulfilling its responsibilities regarding the integrity of the Corporation’s financial statements including the financial reporting process and systems of internal controls, the compliance by the Corporation with legal and regulatory requirements and the qualifications, performance and independence of the Corporation’s external auditor by reviewing:
 - (i) the financial information that will be provided to the shareholders, regulatory authorities and others;
 - (ii) the systems of internal controls management has established;
 - (iii) all audit processes;
 - (iv) all reporting from the external auditors.
- (b) Primary responsibility for the financial reporting, information systems, risk management and internal controls of the Corporation is vested in management and is overseen by the Board. While the Committee has the responsibilities and powers set forth in this Charter, it is not the duty of the Committee to plan or conduct audits or to determine that the Corporation’s financial statements are complete and accurate and are in accordance with generally accepted accounting principles. These are the responsibilities of management and the external auditor. Nor is it the duty of the Committee to conduct investigations, to resolve disagreements, if any, between management and the external auditor or to assure compliance with laws and regulations.

II. COMPOSITION AND OPERATIONS

- (a) The Committee shall be composed of not fewer than three directors, none of whom shall be officers, employees or consultants to the Corporation or any of its related legal entities. The Committee shall only be comprised of unrelated directors. An unrelated director is a director who is independent of management and is free from any interest or other relationship which could reasonably be perceived to materially interfere with the director’s ability to act with a view to the best interests of the Corporation as the case may be, other than interests and relationships arising from shareholding.
- (b) The Committee shall review and reassess this Charter annually.
- (c) All Committee members shall be financially literate (as defined by the Toronto Stock Exchange or other regulatory authority), or shall become financially literate within a reasonable period of time after appointment to the Committee, and at least one member shall have appropriate financial management experience or expertise.

- (d) The Corporation's auditors shall be advised of the names of the Committee members and when appropriate will receive notice of and be invited to attend meetings of the Committee and to be heard at those meetings on matters relating to the auditor's duties.
- (e) The Committee shall meet with the external auditors as it deems appropriate to consider any matter that the Committee or auditors determine should be brought to the attention of the Board or shareholders.
- (f) The Committee shall meet at least four times each year.
- (g) The Committee shall have access to the Corporation's senior management and documents as required to fulfill its responsibilities and is provided with the resources necessary to carry out its responsibilities.
- (h) The Committee shall provide open avenues of communication among management, employees, external auditors and the Board.
- (i) The secretary to the Committee shall be the Corporate Secretary or an appointee of the Corporate Secretary.
- (j) Notice of the time and place of every meeting shall be given to each Committee member at least 48 hours prior to the meeting.
- (k) A majority of the voting membership of the Committee present in person or by telephone or other electronic telecommunication device shall constitute a quorum.
- (l) The President, Chief Executive Officer, Vice President, Finance, and Chief Financial Officer and external auditor would be expected to be available to attend meetings or portions thereof. The external auditors would meet at least twice annually with the Committee. Others may or may not attend the meetings at the sole discretion of the Committee.
- (m) Minutes of Committee meetings shall be approved by the Committee and sent to all directors of the Board.

III. DUTIES AND RESPONSIBILITIES

(a) Financial Statements and Other Financial Information

The Committee will review and recommend for approval to the Board financial information that will be made publicly available. This includes:

- (i) the Corporation's annual and quarterly financial statements;
- (ii) the Corporation's press releases and reports as they relate to the finances of the Corporation;
- (iii) the Management Discussion and Analysis;
- (iv) the financial content of the Annual Report;
- (v) the Annual Information Form and any Prospectus or Private Placement Memorandums; and
- (vi) any reports required by regulatory or government authorities as they relate to the finances of the Corporation.

The Committee will review and discuss:

- (vii) the appropriateness of accounting policies and financial reporting practices to be adopted by the Corporation;
- (viii) any significant proposed changes in financial reporting and accounting policies and practices to be adopted by the Corporation;
- (ix) any new or pending developments in accounting and reporting standards that may affect the Corporation;
- (x) ascertain compliance with the covenants under applicable loan agreements;
- (xi) management's key estimates and judgments that may be material to financial reporting; and
- (xii) any other matters required to be reviewed under applicable legal, regulatory or stock exchange requirements.

(b) Risk Management, Internal Control and Information Systems

The Committee will review and obtain reasonable assurance that the risk management, internal control and information systems are operating effectively to produce accurate, appropriate and timely management and financial information. This includes:

- (i) review the Corporation's risk management controls and policies;
- (ii) obtain reasonable assurance that the information systems are reliable and the systems of internal controls are properly designed and effectively implemented through discussions with and reports from management and the external auditor;
- (iii) review management steps to implement and maintain appropriate internal control procedures including a review of policies;
- (iv) review adequacy of security of information, information systems and recovery plans;
- (v) monitor compliance with statutory and regulatory obligations;
- (vi) review the appointment of the Vice President, Finance and Chief Financial Officer; and
- (vii) review the adequacy of accounting and finance resources.

(c) External Audit

The Committee will review the planning and results of external audit activities and the ongoing relationship with the external auditor. This includes:

- (i) review and recommend to the Board, for shareholder approval, engagement of the external auditor including, as part of such review and recommendation, an evaluation of the external auditors qualifications, independence and performance;
- (ii) review and recommend to the Board the annual external audit plan, including but not limited to the following:
 - 1. engagement letter;

2. objectives and scope of the external audit work;
 3. procedures for quarterly review of financial statements;
 4. materiality limit;
 5. areas of audit risk;
 6. staffing;
 7. timetable; and
 8. proposed fees.
- (iii) meet with the external auditor to discuss the Corporation's quarterly and annual financial statements and the auditor's report including the appropriateness of accounting policies and underlying estimates;
- (iv) review and advise the Board with respect to the planning, conduct and reporting of the annual audit, including but not limited to:
1. any difficulties encountered, or restrictions imposed by management during the annual audit;
 2. any significant accounting or financial reporting issue including the resolution of any disagreement between management and the external auditors;
 3. the auditor's evaluation of the Corporation's system of internal controls, procedures and documentation;
 4. the post audit or management letter containing any findings or recommendation of the external auditor, including management's response thereto and the subsequent follow-up to any identified internal control weakness; and
 5. assess the performance and consider the annual appointment of external auditors for recommendation to the Board;
- (v) review and receive assurances on the independence of the external auditor;
- (vi) review the non-audit services to be provided by the external auditor's firm and consider the impact on the independence of the external audit; and
- (vii) meet periodically with the external auditor without management present.
- (d) Other
- (i) review material litigation and its impact on financial reporting; and
 - (ii) establish procedures for the receipt, retention and treatment of complaints received by the Corporation regarding accounting, internal controls or auditing matters and the confidential, anonymous submission by employees of concerns regarding questionable accounting or auditing matters.

IV. ACCOUNTABILITY

The committee shall report its discussions to the Board by distributing the minutes of its meetings and where appropriate, by oral report at the next Board meeting.

V. STANDARDS OF LIABILITY

Nothing contained in this Charter is intended to expand applicable standards of liability under statutory, regulatory or other legal requirements for the Board or members of the Committee. The purposes and responsibilities outlined in these terms of reference are meant to serve as guidelines rather than inflexible rules and the Committee may adopt such additional procedures and standards as it deems necessary from time to time to fulfill its responsibilities.